UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit AAA: Department, Order No. 202-26-19 (Mar. 23, 2026)

Department of Energy
Washington, DC 20585

Order No. 202-26-19

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States (U.S.) due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The R.M. Schahfer Generating Station ("Schahfer") is an electric generating facility in Wheatfield, Indiana. Schahfer is owned and operated by Northern Indiana Public Service Company (NIPSCO), a division of NiSource Inc. Schahfer consists of two 129 MW natural-gas fired units and two coal-fired units, Unit 17 (423.5 MW) and Unit 18 (423.5 MW).[3] Unit 17 and Unit 18 began operations in 1983 and 1986, respectively. Unit 17 and Unit 18 were both slated to cease operations in December 2025.[4]

Order No. 202-25-12, issued pursuant to FPA section 202(c), required that Schahfer remain in operation for 90 days, through March 23, 2026. This order was based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

Specifically, I determined that MISO faced tight reserve margins due to well documented year-round resource adequacy concerns, particularly during periods of high

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] U.S. Energy Information Administration, *Form EIA-860, Schedule 3: Generator Data* (2024), https://www.eia.gov/electricity/data/eia860/.

[4] As coal-fired facilities, it would be difficult for Schahfer Units 17 and 18 to resume operations once they have been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Schahfer were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

demand or low generation resource output.[5] I determined that the continued operation of Schahfer would provide additional generation capacity during these periods, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.[6] I determined that the continued operation of Schahfer was necessary to alleviate immediate and anticipated threats to reliability.[7]

My determination was based on several facts.

First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area, which covers portions of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, is at an elevated risk "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[8] Additionally, the LTRA notes that "[t]he departure of MISO's coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years."[9]

Second, MISO's year-round resource adequacy concerns are well-documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction (PRA)) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[10] MISO justified this revision by explaining that "Reliability risks associated with [r]esource [a]dequacy have shifted from 'Summer only' to a year-round concern."[11] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[12]

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[5] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc., and Northern Indiana Public Service Company*, Order No. 202-25-12, at 1–4 (Dec. 23, 2025).

[6] *See, e.g.*, *id.* at 1–4.

[7] *See, e.g.*, *id.* at 5.

[8] NERC, *2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[9] *Id.* at 44.

[10] *Midcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

[11] *MISO Transmittal Letter*, FERC Docket No. ER22-495-000, at 3 (Nov. 30, 2021).

[12] *Id.* at 3–4.

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order No. 202-25-12 continue, both in the near and long term.[13] The production of electricity from Schahfer will continue to be critical to maintain reliability in MISO. MISO's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when Schahfer operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 "MaxGen" event for MISO's North and Central Regions due to generation outages, high demand, and transfer capability limits.[14] From January 21–February 1, 2026, Schahfer operated at over 285 MW every day.[15]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[16] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected risk of loss of load in the winter and spring seasons, which, although not as high as in the summer or fall, will nevertheless increase over time.[17]

[13] Further, as noted in Order No. 202-25-12, as a coal-fired facility, it would be difficult for Schahfer to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. If NIPSCO were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required so long as I determine a shortage exists. *See* Order No. 202-25-12 at 1.

[14] *See* Midcontinent ISO on X, (Jan. 24, 2026), https://x.com/MISO_energy/status/2015072060876140805?s=20.

[15] U.S. Dep't of Energy, *FACT SHEET: Energy Department Prevented Blackouts & Saved American Lives During Winter Storms*, (February 2026), https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms.

[16] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[17] *Id.* at 11.

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative*."[18] In a section of that report entitled, "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[19] These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.[20] NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,[21] stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[22] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[23] The 2025 NERC Long-Term Reliability Assessment notes that "MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements."[24] The report observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[25] However, NERC also concluded that "risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high."[26]

While the 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027, two earlier winter studies were more critical. The 2023–2024 NERC Winter Reliability Assessment characterized MISO as a region at elevated risk with the "[p]otential for insufficient operating reserves

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[18] MISO, *MISO's Response to the Reliability Imperative* (Updated February 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.

[19] *Id.* at 12.

[20] NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[21] *Id.* at 7.

[22] *Id.* at 8.

[23] *Id.* at 43.

[24] *Id.* at 15.

[25] *Id.*

[26] *Id.*

in above-normal conditions."[27] These findings were echoed in NERC's 2024–2025 Winter Reliability Assessment, which noted that "[g]enerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[28]

The evidence indicates that there is also a potential longer-term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025–26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[29]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their annual survey, which reported the degree to which expected capacity resources satisfy planning reserve margin requirements.[30] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[31] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[32] It also projected similar results for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[33]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year, while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[34]

Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the

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[27] NERC, *2023–2024 Winter Reliability Assessment*, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

[28] NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

[29] MISO, *Planning Resource Auction: Results for Planning Year 2025–26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

[30] OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025) https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[31] *Id.* at 2.

[32] *Id.* at 7.

[33] *Id.* at 9.

[34] *Id.* at 7, 9.

increase in capacity is largely offset by the projected retirements and does not keep up with the growth in demand.[35]

According to the U.S. Energy Information Administration, coal-fired electricity generation in Indiana has declined from 85% of total generation in 2014 to 42% in 2024. Since 2014, approximately 5,000 MW of coal-fired capacity in Indiana have retired, with almost another 3,900 MW of coal-fired capacity scheduled for retirement by the end of 2028, including Schahfer.[36]

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[37] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away and are provided an additional three-year grace period to commence commercial operations.[38] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[39] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order No. 202-25-12 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and

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[35] *Id.*

[36] *See Electricity,* Energy Information Administration, Indiana Analysis, https://www.eia.gov/states/in/analysis.

[37] *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[38] *Id.* P 84.

[39] *See generally*, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025) ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

extraordinary threat to our Nation's economy, national security, and foreign policy."[40] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[41] In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[42]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[43] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth.

Grid operators—including MISO itself—have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[44]

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[40] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[41] *Id.*

[42] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[43] U.S. Dep't of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-11/DOE%20Final%20EO%20Report%20%28REVISED%20OCT%2027%29.pdf.

[44] *Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce*, Subcomm. on Energy, 119th Cong., at 5 (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/

Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[45] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[46]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[47] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Schahfer Units 17 and 18 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Schahfer Units 17 and 18 shall be made available for operation through June 21, 2026.

Based on my determination of an emergency set forth above, I hereby order:

A. From March 24, 2026, MISO and NIPSCO, shall take all measures necessary to ensure that Schahfer Units 17 and 18 are available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Schahfer Units 17 and 18 to minimize cost to ratepayers. Following the

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files/evo-media-document/witness-testimony_asthana_eng_grid-operators_03.25.2025.pdf.

[45] *Id.* at 6.

[46] *Id.* at 7.

[47] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. NIPSCO is directed to comply with all orders from MISO related to the availability and dispatch of Schahfer Units 17 and 18.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Schahfer Units 17 and 18 have operated in compliance with the allowances contained in this Order.

C. All operation of Schahfer must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.

D. By April 8, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Schahfer Units 17 and 18 consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

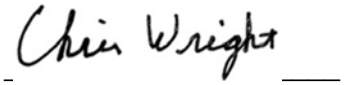
E. NIPSCO is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Schahfer Units 17 and 18 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Schahfer Units 17 and 18 shall not be considered capacity resources.

H. This Order shall be effective from March 24, 2026 through June 21, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 23rd day of March 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commissioners
Chairman Andy Zay
Commissioner Bob Deig
Commissioner Anthony Swinger
Commissioner David Veleta
Commissioner David Ziegner

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The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit BBB: Department, Order No. 202-26-20 (Mar. 23, 2026)

Department of Energy
Washington, DC 20585

Order No. 202-26-20

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States (U.S.) due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The F.B. Culley Generating Station (Culley) is an electric generating facility in Warrick County, Indiana. Culley is owned and operated by CenterPoint Energy and consists of two coal-fired generation units, Unit 2 (103.7 MW) and Unit 3 (265.2 MW), with a combined name plate capacity of 368.9 MW.[3] Unit 2 and Unit 3 began operations in 1966 and 1973, respectively. Unit 2 was slated to cease operations in December 2025.[4]

Order No. 202-25-13, issued pursuant to FPA section 202(c), required that Culley Unit 2 remain in operation for 90 days, through March 23, 2026. This order was based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

Specifically, I determined that MISO faced tight reserve margins due to well-documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.[5] I determined that the continued operation of

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] U.S. Energy Information Administration, *Form EIA-860, Schedule 3: Generator Data* (2024), https://www.eia.gov/electricity/data/eia860/.

[4] As a coal-fired facility, it would be difficult for Culley Unit 2 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Culley were to begin disassembling Unit 2 or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

[5] *See, e.g., Midcontinent Indep. Sys. Operator, Inc., and Northern Indiana Public Service Company*, Order No. 202-25-12, at 1–4 (Dec. 23, 2025).

Culley Unit 2 would provide additional generation capacity during these periods, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.[6] I determined that the continued operation of Culley Unit 2 was necessary to alleviate immediate and anticipated threats to reliability.[7]

My determination was based on several facts.

First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area, which covers portions of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, is at an elevated risk "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[8] Additionally, the LTRA notes that "[t]he departure of MISO's coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years."[9]

Second, MISO's year-round resource adequacy concerns are well-documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[10] MISO justified this revision by explaining that "Reliability risks associated with [r]esource [a]dequacy have shifted from 'Summer only' to a year-round concern."[11] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[12]

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[7] *See, e.g.*, *id.* at 5.

[8] NERC, *2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[9] *Id.* at 44.

[10] *Midcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

[11] *MISO Transmittal Letter*, FERC Docket No. ER22-495-000, at 3 (Nov. 30, 2021).

[12] *Id.* at 3–4.

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order No. 202-25-13 continue, both in the near and long term.[13] The production of electricity from Culley Unit 2 will continue to be critical to maintain reliability in MISO. MISO's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when Culley operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 "MaxGen" event for MISO's North and Central Regions due to generation outages, high demand, and transfer capability limits.[14] From January 21–February 1, 2026, Culley operated at roughly 30 MW almost every day, providing vital generation capacity to the region.[15]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[16] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects risk of loss of load in the winter and spring seasons; although not as high as in the summer or fall, losses will nevertheless increase over time.[17]

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[13] Further, as noted in Order No. 202-25-13, as a coal-fired facility, it would be difficult for Culley Unit 2 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. If CenterPoint Energy were to begin disassembling the unit or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required so long as I determine a shortage exists. *See* Order No. 202-25-13 at 1.

[14] *See* Midcontinent ISO on X, (Jan. 24, 2026), https://x.com/MISO_energy/status/2015072060876140805?s=20.

[15] U.S. Dep't of Energy, *FACT SHEET: Energy Department Prevented Blackouts & Saved American Lives During Winter Storms*, (February 2026), https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms.

[16] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[17] *Id.* at 11.

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative.*"[18] In a section of that report entitled, "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[19] These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment.[20] NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,[21] stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[22] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[23] The 2025 NERC Long-Term Reliability Assessment notes that "MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements."[24] The report observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[25] However, NERC also concluded that "risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high."[26]

While the 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027, two earlier winter studies were more critical. The 2023–2024 NERC Winter Reliability Assessment characterized MISO as a region at elevated risk with the "[p]otential for insufficient operating reserves

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[18] MISO, *MISO's Response to the Reliability Imperative* (Updated February 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final 504018.pdf.

[19] *Id.* at 12.

[20] NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[21] *Id.* at 7.

[22] *Id.* at 8.

[23] *Id.* at 43.

[24] *Id.* at 15.

[25] *Id.*

[26] *Id.*

in above-normal conditions."[27] These findings were echoed in NERC's 2024–2025 Winter Reliability Assessment, which noted that "[g]enerating capacity is 10 GW lower (-6.8%) compared to that of the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[28]

The evidence indicates that there is also a potential longer-term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[29]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their annual survey, which reports the degree to which expected capacity resources satisfy planning reserve margin requirements.[30] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[31] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[32] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[33]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year, while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[34]

Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the

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[27] NERC, *2023 – 2024 Winter Reliability Assessment*, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

[28] NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

[29] MISO, *Planning Resource Auction: Results for Planning Year 2025–26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%20250529_Corrections694160.pdf.

[30] OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025) https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[31] *Id.* at 2.

[32] *Id.* at 7.

[33] *Id.* at 9.

[34] *Id.* at 7, 9.

increase in capacity is largely offset by the projected retirements and does not keep up with the growth in demand.[35]

According to the U.S. Energy Information Administration, coal-fired electricity generation in Indiana has declined from 85% of total generation in 2014 to 42% in 2024. Since 2014, approximately 5,000 MW of coal-fired capacity in Indiana have retired, with almost another 3,900 MW of coal-fired capacity scheduled for retirement by the end of 2028, including Culley.[36]

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[37] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away and are provided an additional three-year grace period to commence commercial operations.[38] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[39] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order No. 202-25-13 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and

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[35] *Id.*

[36] *See Electricity,* Energy Information Administration, Indiana Analysis, https://www.eia.gov/states/in/analysis.

[37] *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[38] *Id.* P 84.

[39] *See generally*, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025) ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

extraordinary threat to our Nation's economy, national security, and foreign policy."[40] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[41] In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[42]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[43] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth.

Grid operators — including MISO itself — have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[44]

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[40] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[41] *Id.*

[42] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[43] U.S. Dep't of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-11/DOE%20Final%20EO%20Report%20%28REVISED%20OCT%2027%29.pdf.

[44] *Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce*, Subcomm. on Energy, 119th Cong., at 5 (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/

Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[45] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[46]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[47] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Culley Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Culley Unit 2 shall be made available for operation through June 21, 2026.

Based on my determination of an emergency set forth above, I hereby order:

A. From March 24, 2026, MISO and CenterPoint Energy shall take all measures necessary to ensure that Culley Unit 2 is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Culley Unit 2 to minimize cost to ratepayers. Following the conclusion of this

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files/evo-media-document/witness-testimony_asthana_eng_grid-operators_03.25.2025.pdf.

[45] *Id.* at 6.

[46] *Id.* at 7.

[47] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. CenterPoint Energy is directed to comply with all orders from MISO related to the availability and dispatch of Culley Unit 2.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Culley Unit 2 has operated in compliance with the allowances contained in this Order.

C. All operations of Culley Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.

D. By April 8, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Culley Unit 2 consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. CenterPoint Energy is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Culley Unit 2 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Culley Unit 2 shall not be considered a capacity resource.

H. This Order shall be effective from March 24, 2026 through June 21, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 23rd day of March 2026.

Chris Wright

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**

Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commissioners
Chairman Andy Zay
Commissioner Bob Deig
Commissioner Anthony Swinger
Commissioner David Veleta
Commissioner David Ziegner

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit CCC: State of Colorado, The State of Colorado's Request for Rehearing, Motion to Intervene, and Stay Request (Jan. 28, 2026)

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I. Introduction

On December 30, 2025, the Department of Energy ("Department") issued Order No. 202-25-14 ("Order")[1] pursuant to its emergency authority under Section 202(c) of the Federal Power Act ("FPA")[2] ("Section 202(c)") to prevent the scheduled retirement of a coal-fired generating unit at the Craig Power Station in Moffat County, Colorado. The Order requires the availability of one coal-fired unit ("Craig Unit 1") from December 30, 2025, to March 30, 2026.

There is no emergency justifying the Department's Order, and even if there were, preventing the retirement of Craig Unit 1 is not the best (or even a reasonable) way to meet the alleged emergency, and does not serve the public interest. The FPA limits the use of Section 202(c) to addressing specific, imminent capacity shortfalls resulting from unexpected outages, natural disasters, extreme weather, and similar circumstances. Here, the Department has declared an emergency due to "a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes" in the Western Electricity Coordinating Council ("WECC") Northwest assessment area.[3] But the Order's emergency determination cannot stand against even the mildest scrutiny.

There is no energy "emergency" as defined by Section 202(c) in the WECC-Northwest assessment area, in Colorado, or in any of the states served by Craig Unit 1. Rather, the Unit's owners and their respective state utility commissions have been

[1] Exhibit A (Department, Order No. 202-25-14 (Dec. 30, 2025) ("Order")).
[2] 16 U.S.C. § 824a(c).
[3] Exhibit A, at 1.

planning for Craig Unit 1's retirement for the last decade.[4] These comprehensive planning processes have ensured that there are reliable and affordable resources available to meet the energy needs in the areas served by Craig Unit 1, such that its long-planned retirement does not create an emergency.

The Department's illegal use of its Section 202(c) authority to require the continued availability of Craig Unit 1, unsupported by any evidence of an imminent energy emergency, will result in unnecessary operational and maintenance costs that could be imposed on ratepayers in Colorado and potentially other states. Continued operation of Craig Unit 1 pursuant to the Order would also cause needless pollution emitted into Colorado and its neighboring states, which the Department failed to meaningfully consider or address, as it was required to do. The Order illegally intrudes on the authority of the states to ensure the resource adequacy of their electric grids and to dictate energy policy within their borders, and improperly attempts to impose the administration's policy preferences on state ratepayers.

Pursuant to Section 313*l* of the FPA,[5] the Colorado Attorney General, on behalf of the State of Colorado, timely submits this request for rehearing and motion to intervene ("Request") seeking rehearing of the Order. The Department should grant rehearing and rescind the Order because it is an unlawful abuse of the Department's emergency authority, is unsupported by evidence showing a true emergency, and is arbitrary and capricious.

[4] Exhibit C (Declaration of Erin O'Neil (Jan. 26, 2026), ¶ 32.
[5] 16 U.S.C. § 825*l*.

II. Motion To Intervene

The State of Colorado moves to intervene in the proceeding initiated by the Order and become a party for purposes of Section 313*l* of the FPA.[6] The State of Colorado is aggrieved by the Order in several ways.

First, households and businesses in Colorado could be required to pay higher electricity bills because of the Order.[7] Through a carefully planned process driven by economic considerations, the owners of Craig Unit 1 planned to retire the Unit and replace it with more cost-effective facilities.[8] By ordering the continued operation of Craig Unit 1, the Order guarantees that Tri-State Generation and Transmission Association, Inc. ("Tri-State"), PacifiCorp, Platte River Power Authority ("PRPA"), Salt River Project, and Public Service Company of Colorado ("Public Service") (together, "Craig Unit 1 Owners"), will incur higher costs to serve their members and customers, which they will then likely seek to pass on to their electricity consumers, including rural customers in Colorado.[9] Although the precise costs and the cost recovery methods are not yet known, it is likely that Colorado ratepayers will bear substantial new costs above what they would have paid absent the Order.[10]

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[6] 16 U.S.C. § 825l.
[7] Exhibit D (Declaration of Joseph Pereira (Jan. 26, 2026)). Because the Order directs the Craig Unit 1 Owners to seek cost recovery the possibility of increased rates is a foreseeable harm for Colorado. Exhibit A, ¶ E. However, Colorado reserves all rights to dispute that costs incurred based on the Order are appropriate.
[8] Tri-State, *Reliable, Lowest-Cost, Reduced Emissions Preferred Portfolio Focus of Tri-State Resource Plan Filing* (Apr. 11, 2025) (last visited Jan. 26, 2026).
[9] Exhibit D, ¶ 11, 18.
[10] Exhibit D.

Second, the Craig Unit 1 Owners determined that it is prudent to retire Craig Unit 1 and replace it with more reliable and cost-effective resources. And the Colorado Public Utilities Commission ("CoPUC") determined that retiring Craig Unit 1 will not affect Tri-State's resource adequacy.[11] By delaying the retirement of a 45 year old coal-fired unit that was not even operable at the time the Order was issued, the Department is causing Colorado's electric customers to be served by a more costly and less reliable and resilient electric grid. Instead of continuing to invest and develop more reliable resources as planned, the Craig Unit 1 Owners will have to dedicate resources to repair and maintain a coal plant that is less reliable and more costly than other generation resources.

Third, Colorado will suffer environmental harms if Craig Unit 1 is required to operate based on the Order. Craig Unit 1 is a significant source of particulate matter ("PM"), nitrogen oxides ("NOx"), sulfur dioxide ("SOx"), carbon monoxide ("CO"), mercury, hazardous air pollutants (HAPs), and greenhouse gas ("GHG") emissions, and its scheduled retirement would have resulted in significant emissions reductions.[12] The Order does not make a meaningful attempt to minimize or mitigate the emissions impact of continued operation of Craig Unit 1 as required. Operating Craig Unit 1 beyond its planned retirement date will increase the amount of pollution emitted in Colorado, harming the environment, public health, and welfare, as well as Colorado's ability to comply with other federal and state environmental laws.[13]

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[11] *See e.g.*, Exhibit E (CoPUC, Decision No. C25-0612, issued on August 26, 2025, in Proceeding No. 23A-0585E), at ¶ 116; CoPUC, Decision No. R22-0191, issued on March 28, 2022, in Proceeding No. 20A-0528E.
[12] Exhibit B, ¶¶ 13-18.
[13] *See* generally, *infra;* Exhibit B, at 15-22.

Finally, state authority over generation resources has been a bedrock principle of the FPA for nearly a century. Federal intrusion in this traditional sphere of state control is permitted only in a true emergency and only with specific procedures that the Department did not follow when issuing the Order. Colorado's sovereign interest in seeing its state laws followed in an area reserved to state sovereign authority further warrants the State's intervention.

III. Background

The Order makes several claims about Colorado's energy resource mix, expected increases in energy demand in the region, and the resulting need for continued availability of Craig Unit 1 to address an alleged energy emergency. The facts on the ground tell a very different story.

A. Craig Unit 1 is owned by several utilities with specific service areas.

Craig Unit 1, along with Craig Units 2 and 3, comprise Craig Station, a 1,285 megawatt ("MW"), generating facility in Moffat County, CO.[14] Craig Units 1 and 2, also known as the Yampa Project, are operated solely by Tri-State but are co-owned by Craig Unit 1 Owners. Craig Unit 1 has a 427 MW capacity and began operating in 1980, making it over 45 years old.[15] Craig Unit 1 was approved to retire on December 31, 2025. Craig Unit 2, which has a 410 MW capacity, has an approved retirement date of September 30, 2028, and Craig Unit 3, which is solely owned and operated by Tri-

[14] *Craig Station Unit 2 owners announce retirement date of Sept. 30, 2028,* Tri-State (July 8, 2020), (last visited Jan. 26, 2026); Exhibit F (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding no. 20A-0528E, Attachment BN-2, (Tri-State, 2020 IRP/ERP, Public (Dec. 1, 2020)), at 182.

[15] Global Energy Monitor, a project of the Sierra Club, *Craig Station* (last updated Jan. 5, 2026) (last visited Jan. 26, 2026); Exhibit F, at 182.

State and has a 448 MW capacity, will retire by 2030. [16] It is Colorado's understanding that, when operating, Craig Unit 1 primarily provides energy to Colorado, as 51% of the unit is owned by Colorado utilities and it is located in Colorado, but provides some energy to Wyoming and Utah, and indirectly to Arizona.

Tri-State is a wholesale electric generation and transmission cooperative association with members located across Colorado, Nebraska, New Mexico, and Wyoming. Tri-State is a non-profit corporation and is owned and governed by its members through a Board of Directors.[17] Tri-State's board is responsible for approving rates, major capital investments, and resource planning decisions.[18] These resource planning decisions must then be approved by the CoPUC. Tri-State's ownership share of Craig Unit 1 is 24%, and Tri-State therefore is entitled to 102.5 MW out of Craig Unit 1's 427 MW capacity.[19] It is Colorado's understanding that within Tri-State's service territory, only Colorado and Wyoming receive energy from Craig Unit 1.

PRPA and Public Service are the two other Colorado-based utilities with an ownership stake in Craig Unit 1. PRPA is a non-profit community-owned power generation and transmission utility that provides energy to Estes Park, Fort Collins, Longmont, and Loveland, Colorado.[20] PRPA has an 18% ownership share of Craig Unit 1

[16] Tri-State, *Craig Station Unit 2 Retirement* (July 8, 2020); Exhibit F, at 182; Exhibit G (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-1 (Tri-State, Responsible Energy Plan ("Responsible Energy Plan") (Jan. 2020)), at 3.
[17] Exhibit JJ (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Proceeding 20A-0528E), at 13:8-13.
[18] *Id.*, at 13:16-22.
[19] Exhibit J (CoPUC, 120 Day ERP Implementation Report, Public, filed on April 11, 2025, in Proceeding No. 23A-0585E).
[20] Exhibit EE (PRPA, *2024 Integrated Resource Plan* (Apr. 2023)).

and therefore is entitled to 77 MW of Craig Unit 1's capacity.[21] Public Service is a subsidiary of Xcel Energy, Inc., and is the largest gas and electric provider in Colorado. However, Public Service has the smallest ownership stake in Craig Unit 1, owning 9% (38.4 MW of the unit's total capacity).[22]

The Salt River Project and PacifiCorp are the two non-Colorado owners of Craig Unit 1. The Salt River Project is a non-profit organization that provides power in central Arizona.[23] The Salt River Project owns 29% of Craig Unit 1 (124 MW of the unit's total capacity).[24] However, the Salt River Project does not receive energy from Craig Unit 1 directly and instead trades for it through the Western Area Power Administration ("WAPA"). Their contract for exchanging this power through WAPA will expire on April 1, 2026. PacifiCorp is based in Oregon but serves customers in Oregon, Washington, California, Utah, Idaho, and Wyoming. PacifiCorp has a 19% ownership of Craig Unit 1 (81 MW of the unit's total capacity). It is Colorado's understanding that within PacifiCorp's service territory, only Utah and Wyoming receive energy from Craig Unit 1.

B. The Craig Unit 1 Owners decided to retire Craig Unit 1 ten years ago and included the retirement in their resource plans.

In 2016, the Craig Unit 1 Owners voluntarily decided to retire Craig Unit 1 by December 31, 2025, based on "the state and federal regulatory environment for coal-based generation, current and forecasted market conditions, the significant costs to

[21] Exhibit FF (PRPA, *Craig Units 1&2 (Yampa Project)* (2026)).
[22] *Craig Station*, Global Energy Monitor.
[23] Exhibit H (Salt River Project, *2023 Integrated Systems Plan*) at 6.
[24] *Id.,* at 27.

install additional emissions controls, and the best interests of electric consumers."[25] The Craig Unit 1 Owners agreed to proposed revisions to Air Quality Control Commission Regulation No. 23 and Colorado's Regional Haze State Implementation Plan ("SIP") that included the December 31, 2025 retirement date.[26] The U.S. Environmental Protection Agency ("EPA") approved Craig Unit 1's retirement date on July 5, 2018.[27] Since 2016, the Craig Unit 1 Owners have incorporated the planned closure of the unit as an assumption in all ERP proceedings, reports, decisions and modeling.[28] None of these processes or reports conclude that resource adequacy or reliability would be threatened by the unit's retirement.

Tri-States' resource plans are overseen by the CoPUC. The CoPUC reviewed Tri-State's load forecasts, resource needs, and planned resource acquisitions, all of which included the retirement of Craig Unit 1 by December 31, 2025 as an underlying assumption, as part of Tri-State's 2020 ERP and most recently its 2023 ERP for planning years 2026-2031.[29] As recently as August 2025, the CoPUC found that "Craig Unit 1 is not required for reliability or resource adequacy purposes based on the record in this ERP. Every portfolio that Tri-State modeled for its most recent ERP

[25] Tri-State, *Craig Station Owners, Regulators and Environmental Groups Reach Agreement on Proposed Revisions to Colorado Regional Haze Plan* (Sept. 1, 2016).
[26] *See id.*; 5 Colo. Code Reg. § 1001-27, Part A, Section IV.D.1 (2025).
[27] Air Plan Partial Approval and Partial Disapproval; Colorado; Regional Haze Plan for the Second Implementation Period, 83 Fed. Reg. 31,332 (July 5, 2018).
[28] Tri-State, *Craig Station Owners Agreement*; *e.g.*, CoPUC, *Tri-State, ERP Annual Progress Report, Revised*, filed on June 2, 2017, in Proceeding No. 15M-0852E, at 16; CoPUC, ERP for Annual Progress Report, filed on October 31, 2018, in Proceeding No. 15M-0852E, at 17; CoPUC, ERP Annual Progress Report, filed on December 10, 2019, in Proceeding No. 15M-0852E, at 22.
[29] Exhibit F, at 31; CoPUC, 150-Day Report, Public, filed on February 13, 2023, in Proceeding No. 20A-0528E, at 28; Exhibit X (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 (Tri-State, 2023 ERP Phase I, Rev. 2 (Apr. 22, 2024)), at 19, 21, 32, 44, 55, 66; Exhibit J, at 21, 32, 43, 54, 64, 75.

assumes that Craig Unit 1 retires at the end of 2025. . . every portfolio meets all reliability metrics and is reliable." The CoPUC further found that Tri-State's resource plan—including the retirement of Craig Unit 1—is resource diverse and cost effective, ensuring energy security, economic prosperity, and environmental protection. And the ERP progress report filed by Tri-State on December 1, 2025, did not present any resource adequacy or reliability issues, and continues to project no capacity shortfalls through 2035. Tri-State reaffirmed on January 23rd that the Craig Unit 1 retirement "has informed operational and maintenance decisions, and Tri-State has planned for adequate resources to maintain reliability on its system following the unit's retirement."[30] Public Service, which also engages in the ERP process with the CoPUC for review of its resource adequacy and reliability, has not indicated in its CoPUC filings a need for energy from Craig Unit 1 to meet any immediate or longer-term resource needs. Neither has PRPA, which conducts its own integrated resource planning process.

The other Craig Unit 1 Owners are subject to similar oversight by their state utility commissions, and since Tri-State's service territory also includes Wyoming, its extensive planning addresses resource adequacy there as well. As part of their respective state-approved resource plans, Salt River Project and PacifiCorp have confirmed there are no resource adequacy concerns in their respective states associated with the retirement of Craig Unit 1.

[30] Tri-State, *Tri-State makes Craig Generating Station Unit 1 available to operate in compliance with DOE emergency order* (Jan. 23, 2026).

Underscoring the lack of need for Craig Unit 1, the unit suffered an outage on December 19, 2025 due to a mechanical failure of a valve.[31] Absent the Order, it is unlikely the Owners would have expended new resources to repair the aging unit given that they were not expecting to use it to generate energy after December 31st.

C. Federal Energy Regulatory Commission ("FERC") and its designated entities also oversee resource planning decisions for Craig Station to ensure reliability.

The structure of FERC's management of the bulk power system is important to understand various studies and reports as they relate to the claimed emergency identified in the Order. The Craig Unit 1 Owners are currently not part of a Regional Transmission Organization ("RTO") or Independent System Operator ("ISO"). The reliability and resource adequacy of the electric power system in states that are not in RTOs or ISOs are typically managed by individual utilities, which are often vertically integrated, meaning they handle generation, transmission, and distribution of electricity within their service areas, and are typically overseen by state public utilities commissions or a similar state entity.[32] Although the utilities served by Craig Unit 1 are not in an RTO or ISO, they are subject to reliability oversight by FERC and several balancing authorities, in addition to being managed by their state resource planning and reliability requirements. These related processes are designed to govern long-term planning and resource adequacy, and are reserved to FERC and the states under the FPA.[33]

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[31] Exhibit QQ (Tri-State, *U.S. DOE Orders Tri-State to Keep Craig Generating Station Unit Operating for Next 90 Days* (Dec. 31, 2025)); *see also* Exhibit B, ¶ 11; Exhibit D, ¶ 15.
[32] FERC (Office of Public Participation), *Energy Markets* (last updated August 18, 2025) (last visited Jan. 26, 2026).
[33] *See* 16 U.S.C. § 824(b)(1); 16 U.S.C. § 824a(b).

FERC oversees the reliability of the bulk power system, which is the network of generation, transmission, and distribution system components across the United States, by reviewing, approving, and enforcing mandatory reliability standards developed by the North American Electric Reliability Corporation ("NERC").[34] FERC designated NERC as the Electric Reliability Organization ("ERO") for the mainland United States in 2006 pursuant to the Energy Policy Act of 2005.[35] NERC is a non-profit international regulatory authority that assures the reliability of North America's bulk power system by creating reliability standards, approved by FERC, that are legally enforceable and include training and communications requirements, and emergency back up plans.[36] These standards apply to all users, owners, and operators of the continental United States' bulk power system.[37] NERC also annually analyzes seasonal and long-term reliability of the bulk power system and assess risk by region using a three-tiered system.[38]

NERC is permitted to delegate authority to regional entities for the purpose of proposing and enforcing reliability standards.[39] NERC therefore divides the North American bulk power system into six regional entities to which it has delegated authority. One of these regional entities is the WECC, which covers most of the Western United States, including all of the states served by Craig Unit 1.[40] WECC is a

[34] FERC (Office of Public Participation), *Reliability Explainer* (last updated Aug. 16, 2023) (last visited Jan. 26, 2026).
[35] *See id.*; 16 U.S.C. § 824*o*(a)(2); N. Am. Elec. Reliab. Corp., 116 FERC ¶ 61,062 (2006), at 3, order on reh'g & compliance, 117 FERC ¶ 61,126 (2006).
[36] *Reliability Explainer*, FERC.
[37] 16 U.S.C. § 824o(b)(1).
[38] *See* 18 C.F.R. § 39.11.
[39] 18 C.F.R. § 39.8.
[40] *See* Fully Executed *Amended And Restated Delegation Agreement Between NAERC And WECC* (2021 FERC Revisions – Clean), North American Electric Reliability Corp. (January 1, 2021)

non-profit organization that assures a reliable electric system in the Western Interconnection, a region that covers the Pacific Ocean to the Rocky Mountain states.[41] All of the Craig Unit 1 Owners are members of WECC.[42]

WECC identifies and registers the Reliability Coordinators and balancing authorities that are responsible for maintaining operating conditions under NERC's reliability standards within its region.[43] Reliability Coordinators are the highest level of authority under NERC. They are responsible for the operation of the bulk electric system and have the operating tools, procedures, and authority to prevent or mitigate emergency operating situations.[44] Balancing authorities ensure that power system demand and supply are balanced, manage transfers of electricity and use economic dispatch to optimize the use of generating units and minimize real-time costs, and maintain operating conditions under NERC reliability standards.[45] Southwest Power Pool, Inc. ("SPP") is the Reliability Coordinator for Public Service, Tri-State, and PRPA.[46] WAPA – Rocky Mountain Region Western Area Colorado Missouri ("WACM") is the Balancing Authority for Craig Station.

In addition to this structure, Public Service, PRPA, and Tri-State are now part of the Western Energy Imbalance Market ("WEIS") market, which is a "real-time energy imbalance service market that provides market participants the ability to submit offers to sell and bids to buy imbalance energy, and settles the net supply or

[41] EPA, *U.S. Grid Regions* (Nov. 24, 2025).
[42] WECC, *Membership* (2026).
[43] Department, *Learning Series: Energy Security & Resilience*; WECC, *Registration and Certification* (2026).
[44] NERC, *NERCipedia: Reliability Coordinator* (2024).
[45] Department, *Learning Series: Energy Security & Resilience*.
[46] SPP, *Western RC Services* (2026).

obligation for an asset owner."[47] In July of 2025, Public Service was approved to join Markets+, a regional, day-ahead and real-time energy and flexibility reserve product market in the Western Interconnection.[48] Both WEIS and Markets+ are operated by SPP, but are separate from the RTO that SPP also operates.[49] And in December 2025, the CoPUC determined that it is in the public interest for Tri-State to join the SPP's RTO in the Western Interconnection in April of 2026.[50]

The Order states, without support, that the WECC-Northwest Assessment area is experiencing an energy emergency based on NERC's 2024 Long-Term Reliability Assessment ("2024 LTRA"). But NERC, WECC and its designees have not made a similar determination. The Order merely cites to the 2024 LTRA's statement that energy variability is greater in the WECC-Northwest area than other regions, and that supply chain issues are a concern.[51] In the 2024 LTRA, the WECC-Northwest Assessment area included Colorado, Idaho, Montana, Oregon, Utah, Washington and Wyoming. However, in NERC's two more recent assessments, its 2025 Summer Reliability Assessment ("SRA") and 2025-2026 Winter Reliability Assessment ("WRA"), the WECC-Northwest Assessment area no longer includes Colorado and Wyoming, which were moved to the WECC-Rocky Mountain assessment area, or Utah, which is in the WECC-Basin assessment area.[52]

[47] SPP, *Western Energy Imbalance Service (WEIS) Quarterly State of the Market* (Feb. 13, 2024) at 4.
[48] CoPUC, Decision No. C25-0697, issued on October 9, 2025, in Proceeding No. 25A-0075E.
[49] SPP, *About Us* (2026).
[50] CoPUC, Decision No. C25-0906, issued on December 16, 2025, in Proceeding No. 25A-0266E, ¶ 2.
[51] Exhibit K (NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024)).
[52] Exhibit L (NERC, *2025-2026 WRA* (Nov. 2025); NERC, *2025 SRA* (May 2025).

In light of this reorganization of the assessment areas, and given the timing of Order, the 2025-2026 WRA is a more relevant assessment for evaluating near-term reliability issues since the WRA specifically covers the upcoming three-month winter period (December-February). This assessment found that "[a]ll assessed areas have adequate resources for normal winter peak load conditions[.]"[53] The 2025-2026 WRA found that WECC-Rocky Mountain, the region that includes Colorado and most of Wyoming, would not require reliance on imports to maintain resource adequacy "under combined extreme peak and extreme derated conditions" and that all assessed areas have adequate resources for normal winter peak load conditions.[54]

Thus, the assessments covering the areas served by Craig Unit 1 for both the 90 day term of the Order and beyond do not conclude that there is an energy shortfall or a reliability concern. Yet, the day before Craig Unit 1's planned retirement, the Department issued a Section 202(c) Order declaring that an emergency exists within the WECC-Northwest assessment area "due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes…"[55] The Order requires the Craig Unit 1 Owners to ensure that the unit is available to operate for the next 90 days at the direction of WACM in its role as Balancing Authority or the SPP West in its role as Reliability Coordinator.[56]

[53] Exhibit L at 5.
[54] *Id.,* at 38.
[55] Exhibit A at 1.
[56] *Id*. at 3-4.

D. The Craig Order is in line with other federal efforts to support the coal industry.

On January 20, 2025, President Trump issued Executive Order 14156, "Declaring a National Energy Emergency."[57] That declaration did not provide any factual support for its assertion that the country was in the grips of an electricity emergency. In fact, U.S energy production is at an all-time high and continues to grow.[58] Although the President recently extended the energy emergency declaration for an additional year, he did not cite any new evidence to justify the supposed emergency.[59]

Setting the stage for the Department's plan to use Section 202(c) orders to promote the administration's policy preferences for the nation's energy mix, on April 14, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid."[60] This Executive Order directed the Department to streamline and expedite processes for issuing emergency orders under Section 202(c). It also ordered the preparation of a methodology to help identify areas with inadequate reserve margins and directed the use of Section 202(c) orders to prevent certain generation resources from leaving the bulk power system.[61] Pursuant to this Executive Order, the Department published its report titled *Resource*

[57] Declaring a National Energy Emergency, 90 Fed. Reg. 8433 (Jan. 20, 2025).
[58] Victoria Zaretskaya, *The United States was the world's largest liquified natural gas exporter in 2023*, U.S. Energy Info. Admin.: Today in Energy: In-Brief Analysis (Apr. 1, 2024); U.S. Energy Info. Admin., *U.S. Exports of Crude Oil* (last updated Dec. 31, 2025); U.S. Energy Info. Admin., *U.S. Energy Facts Explained: Imports & Exports* (last updated July 15, 2024).
[59] Continuation of the National Emergency With Respect to Energy, 91 Fed. Reg. 1667 (Jan. 12, 2026).
[60] Exec. Order 14262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521 (Apr. 14, 2025).
[61] 90 Fed. Reg. 15521.

Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid ("Resource Adequacy Report" or "Report"),[62] on July 7, 2025.

Colorado and several other states filed a request for rehearing of the Resource Adequacy Report that pointed out the Report's many analytical errors, including flawed and unexplained assumptions for load growth projections and resource retirements and additions.[63] The Department itself acknowledges in the Report that the agency is not equipped to analyze resource adequacy, stating that its own analysis "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[64] Thus, despite issuing a Report intended to guide its use of Section 202(c) authority, the Department does not have the ability to discern whether there is an energy emergency at the regional level.

Nevertheless, the Department proceeded to issue numerous orders under Section 202(c) in 2025 to prevent the retirement of several fossil fuel-fired power plants across the country. In May 2025, the Department issued orders preventing two fossil-fuel generation facilities in Michigan and Pennsylvania from retiring as planned. Both orders failed to identify an imminent energy emergency justifying the units' continued operation, and instead cited only generalized concerns about resource adequacy.[65] Both orders have since been reissued multiple times.[66]

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[62] Exhibit M (Department, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (July 2025)).
[63] Exhibit N (Motion to Intervene and Protective Request for Rehearing by the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York, filed on August 6, 2025 with the Department).
[64] Exhibit M, at 2.
[65] Exhibit O (Department, Order No. 202-25-3 ("Campbell Order") (May 23, 2025)); Exhibit P (Department, Order 202-25-4 ("Eddystone Order") (May 30, 2025)).
[66] *See* Exhibit I (Department, Order No. 202-25-7 (Aug. 20, 2025") ("Aug. Campbell Extension")); Exhibit U (Department, Order No. 202-25-9 (Nov. 18, 2025) ("Nov. Campbell Extension"); Exhibit V

In December 2025, four additional fossil fuel-fired generation facilities were scheduled to retire, and the Department again issued orders requiring their continued availability. In addition to the Craig Order at issue in this proceeding, the Department ordered that units in Washington and Indiana remain available to operate.[67] Like the Craig Order, the other Section 202(c) orders issued in December also failed to support their emergency determinations with evidence of a specific, imminent energy shortfall or other circumstances that qualify as an emergency under Section 202(c).

IV. Statement Of Issues and Specifications of Error

The State of Colorado submits the following statement of issues and specifications of error:

1. The Order is contrary to law because Section 202(c) only authorizes the Department to respond to specific, imminent, unexpected, and temporary events, while the Order addresses long-term resource adequacy concerns. The statutory text, legislative history, judicial construction, and the Department's regulations all confirm that an emergency must be specific, imminent, unexpected, and temporary. 16 U.S.C. § 824a(c); *Richmond Power & Light of City of Richmond, Ind. v. FERC*, 574 F.2d 610 (D.C. Cir. 1978); S. Rep. No. 74 621, 74th Cong., 1st Sess. (1935); 16 U.S.C. § 824a(a) & (b); *Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232 (8th Cir. 1970).

2. The Order is contrary to law because it exceeds the Department's statutory authority by preventing the long-planned retirement of Craig Unit 1. Section 201(b) of the FPA reserves decisions about plant retirement dates to the states, and Section 202(c) does not vest the Department with general regulatory authority over resource adequacy. By abusing a statute meant only for emergencies, the Order intrudes on authority reserved to states and to other federal regulators to regulate resource adequacy. 16 U.S.C. §824(a); *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009); *see also Hughes v. Talen*

(Department, Order No. 202-25-8 (Aug. 28, 2025) ("Aug. Eddystone Extension")); Exhibit PP (Department, Order No. 202-25-10 (Nov. 25, 2025) ("Nov. Eddystone Extension")).

[67] Exhibit Q (Department, Order No. 202-25-11 (Dec. 16, 2025) ("Centralia Order")); Exhibit S (Department, Order No. 202-25-12 (Dec. 23, 2025) ("Schahfer Order")); Exhibit R (Department, Order No. 202-25-13 (Dec. 23, 2025) ("Culley Order")).

Energy Mktg., LLC, 578 U.S. 150, 155 (2016); *Devon Power LLC et al.*, 109 FERC ¶ 61,154, P 47 (2004).

3. The Order's determinations are not supported by substantial evidence demonstrating an actual emergency, as indicated by the statutory text and structure and defined in Department regulations, that would necessitate continued operation of Craig Unit 1. The Order fails to exercise reasoned decision making and ignores critical facts, including the findings in its own Resource Adequacy Report, NERC's findings, and state and utility analyses. 16 U.S.C. § 824a(c); *Jarecki v. G.D. Searle & Co.*, 367 U.S. 303 (1961); *Richmond Power & Light of City of Richmond, Ind. v. FERC*, 574 F.2d 610 (D.C. Cir. 1978); S. Rep. No. 74-621 (1935); 16 U.S.C. § 824a(a) & (b); *Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232 (8th Cir. 1970); 16 U.S.C. § 824o;;10 C.F.R. § 205.371; 10 C.F.R. § 205.375; *Emera Maine v. FERC*, 854 F.3d 9, 22 (D.C. Cir. 2017); *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983; *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168(1962).

4. The Order is contrary to law because it fails to present substantial evidence for its emergency determination and ignores critical facts. None of the materials cited in the order provide evidence of an emergency in the WECC-Northwest assessment area or regions served by Craig Unit 1. *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983); *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962); Chritton v. National Transportation Safety Board, 888 F.2d 854, 856 (D.C. App. 1989); *Emera Maine v. FERC*, 854 F.3d 9, 22 (D.C. Cir. 2017).

5. The Order is arbitrary and capricious because it fails to require generation that best meets the claimed emergency. 16 U.S.C. § 824a(c)(1); *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208 (2009); *Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1 (2020); *Motor Vehicle Mfrs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983); 10 C.F.R. § 205.371;

6. The Order's terms fail to comply with Section 202(c)'s requirements. 16 USC § 824a(c)(1); 16 U.S.C. § 824a(c)(2); *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009); *see also, e.g., Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 155 (2016).

7. The Order is arbitrary and capricious because it is designed to support the federal administration's policy goal of supporting the coal industry. Dep't of Commerce v. New York, 588 U.S. at 782; Level the Playing Field v. FEC, 961 F.3d 462, 464 (D.C. Cir. 2020) (quoting Hagelin v. FEC, 411 F.3d 237, 242 (D.C. Cir. 2005))

8. The Order violates the National Environmental Policy Act ("NEPA") because it fails to assess the environmental consequences of a major federal action significantly affecting the human environment. 42 U.S.C. § 4321; *et seq.*; 10 CFR § 1021.103.

V. Request For Rehearing

The Department must grant rehearing and rescind the Order because it suffers from numerous legal and factual deficiencies. Ignoring the legal standards that constrain the exercise of emergency authority under Section 202(c), and acting in disregard of the facts, the Order improperly impinges on state authority over resource planning decisions, imposes unreasonable and unnecessary costs, fails to include required provisions to minimize environmental harms, and advances the administration's preferred energy source with no reasonable basis. For these reasons, the Order is contrary to law, arbitrary and capricious, and unsupported by substantial evidence. The Department should withdraw it.

A. The Order is contrary to law because it improperly expands the use of Section 202(c)'s emergency authority beyond the limited scope set forth in the FPA.

Section 202(c) authorizes the Department to command action from a utility unconstrained by many of the core procedural safeguards, jurisdictional boundaries, and substantive limitations normally imposed by the FPA.[68] This power far exceeds the Department's normal authority, and is therefore restricted to the extraordinary and limited circumstances set forth in the statute.[69] The FPA's statutory text and

[68] *See* 16 U.S.C. § 824a(c).
[69] *Id.* ("[d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes…").

structure, along with the Department's regulations, historic practice, and case law interpreting the FPA all make clear that any such event, including a "shortage of electric energy" or the "demand for electric energy" must be one that constitutes a bona fide "emergency"—*i.e.*, a specific, imminent, unexpected and temporary event. The Order exceeds the Department's authority because those extraordinary and limited circumstances do not exist here, and the Department is instead attempting to use the Order to regulate long term resource adequacy, which is expressly reserved to the states and FERC.

i. The language, history and structure of Section 202(c) limit the Department to addressing specific, imminent, unexpected and temporary supply shortfalls.

Section 202(c)'s text authorizes the Department to act only upon an "emergency."[70] The statute itself does not define "emergency."[71] At the time Section 202(c) was enacted, "emergency" was defined as a "sudden or unexpected appearance or occurrence…An unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency."[72] Contemporary dictionaries likewise define "emergency" as "an unforeseen combination of circumstances or the resulting state that calls for immediate action," or an "urgent need for assistance or relief."[73]

[70] *Id.*
[71] Although emergency is not defined, the statute does indicate that an emergency includes "the continuance of any war in which the United States is engaged." 16 U.S.C. § 824a(c)(1).
[72] *Emergency*, Webster's New International Dictionary of the English Language (1930).
[73] *Emergency*, Merriam-Webster Dictionary (Jan. 11, 2026); *See* also Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789, 812 n.147 (2025) (noting that dictionaries have given the term "emergency" the "same meaning for many years").

The remainder of Section 202(c)'s plain language also underscores the urgency and immediacy inherent in the word "emergency." The text's use of the present tense underscores its focus on imminent and certain shortfalls, empowering the Department to act only where "an emergency exists."[74] That near-term focus, along with the fact that this Section 202(c) authority is "temporary" authority,[75] precludes use of Section 202(c) to pursue long-term policy goals such as preference for a particular fuel source[76] or interventions to address general concerns about long-term resource adequacy.[77]

The legislative history of the FPA confirms that Congress intended Section 202(c) authority to be used for true emergencies. In a report accompanying the FPA's original passage in 1935, Section 202(c) is described as a "temporary power" to be used in response to "crises:"

> This is a temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose. Drought and other natural emergencies have created similar crises in certain sections of the country; such conditions should find a Federal agency ready to do all that can be done in order to prevent a break-down in electric supply.[78]

[74] 16 U.S.C. § 824a(c).
[75] *Id.*
[76] *Richmond Power & Light*, 574 F.2d at 615 (Section 202(c) "is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.").
[77] *See Coalition for Competitive Electricity, Dynergy Inc. v. Zibelman*, 906 F.3d 41, 50 (2018) (citing 16 U.S.C. § 824(b)) (FPA "leaves to the States alone" the authority "to regulate energy production and facilities used for the generation of electric energy"); *see also Arkansas Elec. Co-op Corp. v. Arkansas Public Service Com'n*, 461 U.S. 375, 377 (1983) ("[T]he regulation of utilities is one of the most important of the functions traditionally associated with the police power of the States.").
[78] S. Rep. No. 74-621 at 49 (1935).

Section 202's overall structure also highlights Section 202(c)'s emphasis on imminent, near-term concerns. Section 202 established three tiers of federal involvement in grid coordination. Section 202(a)[79] and Section 202(b)[80] together define and limit the tools by which the federal government may pursue "abundant" energy supplies in the normal course. Section 202(a) states that the federal government may seek "abundant supply of electric energy" by "divid[ing] the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy." Section 202(b) provides a backstop if the voluntary interconnection and coordination provided for in Section 202(a) fails, allowing the federal government to order "physical connection . . . to sell energy or to exchange energy" upon application, and "after an opportunity for hearing."[81] However, Section 202(b) specifically states that the government has "no authority to compel the enlargement of generating facilities for such purposes."[82]

The resulting statutory "machinery for the promotion of the coordination of electric facilities" comprises the following: in subsection (a), an instruction to establish a general framework meant to facilitate "coordination by voluntary action;" in subsection (b), "limited authority to compel interstate utilities to connect their lines and sell or exchange energy," subject to defined procedural and substantive requirements, when "interconnection cannot be secured by voluntary action;" and in subsection (c), "much broader" but "temporary" authority "to compel the connection

[79] 16 U.S.C. § 824a(a).
[80] 16 U.S.C. § 824a(b).
[81] *Id.*
[82] *Id.*

of facilities and the generation, delivery, or interchange of energy during times of war or other emergency."[83]

This structure relies on voluntary action for everyday energy planning, specifies limited authority where that voluntary system fails, and allows for "temporary" central command-and-control only in case of "emergency." Section 202(c) authority applies narrowly to immediate and unavoidable "break-down[s] in electric supply," rather than mere desire for more abundant supply in the future.[84] Interpreting Section 202(c)'s "emergency" powers to encompass longer-term concerns such as potential shortfall years into the future would unwind the careful balance of voluntary, market-driven action and federal authority set out by Congress. Therefore, such an interpretation cannot be squared with the statutory text, history and structure of Section 202 as required by law.

ii. Section 215 of the FPA explicitly assigns federal regulation of long term resource adequacy to FERC, further emphasizing that the Department's Section 202(c) authority is limited to imminent emergencies.

Section 215 of the FPA, 16 U.S.C. § 824o ("Section 215"), which delineates the scope of federal power to enforce mandatory long-term reliability requirements, confirms that Section 202(c) cannot be used to enforce the Department's preference for long-term reliability solutions. Congress added Section 215 to the FPA in 2005 precisely because the FPA as it then existed, which included Section 202(c), did not provide the federal government with the power to enforce measures designed to

[83] S. Rep. No. 74-621 at 49 (1935).
[84] *Id.*

ensure broad, long-term reliability.[85] Implementation of Section 215, including the approval and enforcement of reliability standards for all entities operating in the bulk power system, is left to FERC and its designated ERO, not the Department.[86]

By enacting Section 215, Congress newly created a comprehensive and carefully circumscribed scheme to allow FERC—not the Department—to address long-term reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent "of the users and owners and operators of the bulk-power system" but with "fair stakeholder representation."[87] FERC may approve or remand those standards (but not replace them with its own) and must "give due weight" to NERC's "technical expertise" while independently assessing effects on "competition."[88] Section 215 specifies enforcement mechanisms and procedures for reliability standards and carefully preserves state authority over "the construction of additional generation" and

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[85] *See* Rules Concerning Certification of the ERO; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards, 70 Fed. Reg. 53,117, 53,118 (Sept. 7, 2005) ("In 2001, President Bush proposed making Electric Reliability Standards mandatory and enforceable[,]" leading to enactment of Section 215 in 2005); National Energy Policy Development Group, *Reliable, Affordable, and Environmentally Sound Energy for America's Future* (May 2001) at 7-6 (noting that "[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country" and that "[o]ne factor limiting reliability is the lack of enforceable reliability standards" because "the reliability of the U.S. transmission grid has depended entirely on voluntary compliance," and then recommending "legislation providing for enforcement" of reliability standards) (emphasis added); S. Rep. No. 109-78,109th Cong., 1st Sess. at 48, Section 1211 (2005) (Section 215 "changes our current voluntary rules system to a mandatory rules system" for long-term reliability); *see Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005, "the reliability of the nation's bulk-power system depended on participants' voluntary compliance with industry standards").

[86] 16 U.S.C. § 824o.

[87] 16 U.S.C. § 824o(c)(2)(A); *see also id*. § 824o(a)(3) (defining reliability standards as "a requirement … to provide for reliable operation of the bulk-power system").

[88] *Id*. § 824o(d)(2)-(4).

regulation of in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards.[89]

Interpreting Section 202(c) to permit the Department to mandate generation based on its determination that non-imminent and unsubstantiated reliability concerns create an "emergency" would effectively allow the Department to bypass Section 215's procedural safeguards, constraints on federal authority, and protection of state power over long-term reliability. This would impermissibly contradict Congress' clear intent as expressed in its more recent reliability-specific provisions, enacted with the understanding that the Department had no authority to address long-term reliability through Section 202(c).[90] "Congress's specific and limited enumeration of [agency] power" over a particular matter in one section of the FPA "is strong evidence that [a separate section] confers no such authority on [an agency]."[91] Congress has, in Section 215, directly established the mechanisms by which the federal government may compel action to ensure long-term electric-system reliability, and that authority does not rest with the Department. In so doing, Congress has confirmed that the word "emergency," as used in Section 202(c), does not extend to long-term reliability concerns and only applies to specific, imminent, unexpected and temporary events.

[89] *Id*. §§ 824o(e), -(i)-(j).
[90] *See also FDA v. Brown & Williamson Tobacco Corp*., 529 U.S. 120, 121 (2000) ("The meaning of one statute may be affected by other Acts, particularly where Congress has spoken subsequently and more specifically to the topic at hand.").
[91] *Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401 (D.C. Cir. 2004).

iii. The Order is arbitrary, capricious and contrary to law because it contradicts the Department's regulations interpreting Section 202(c) and its historic practice in applying Section 202(c).

The Department's regulations confirm that Section 202(c)'s authority is confined to imminent and unexpected resource shortages rather than long-term reliability concerns. Those regulations define "emergency" for the purposes of Section 202(c) to mean circumstances that arise suddenly and unexpectedly:

> "Emergency," as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected "entity" to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities.[92]

This focus on specific events like weather conditions, acts of God, or unforeseen circumstances outside of the power of the affected entity to prevent, along with the reference to a "sudden increase in customer demand" producing a "specific inadequate power supply situation,"[93] foreclose the Department from using 202(c) authority to address vague long-term supply and reliability issues, such as those articulated in the Order.

This need for specificity is repeated in the Department's regulations defining an inadequate energy supply: "[a] system may be considered to have inadequate" supply when "the projected energy deficiency…will cause the applicant [for a 202(c)

[92] 10 C.F.R. § 205.371.
[93] *Id.*

Order] to be unable to meet its normal peak load requirements based upon use of all of its otherwise available resources so that it is unable to supply adequate electric service to its ultimate customers."[94] An emergency may exist where past planning failures produce an immediate, present-tense shortfall, but the Department has no authority to commandeer long-term planning merely because it deems current plans inadequate to meet long-term needs.[95] As the Department stated when it promulgated these regulations, the statute allows the Department to provide "assistance [to a utility] during a period of unexpected inadequate supply of electricity," but does not empower it to "solve long-term problems."[96]

Until 2025, the Department's orders complied with this regulatory scheme and the agency used its Section 202(c) authority only in response to concrete, particularized emergencies, subject to narrow, appropriate limitations. Established "practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred."[97] Until recently, the Department has used Section 202(c) to address specific, imminent, and unexpected shortages, never to address longer-term reliability concerns or demand forecasts.[98] As pointed out by the Congressional

[94] 10 C.F.R. § 205.375.
[95] *See id.* (requiring present inability to meet demand to demonstrate inadequate energy supply).
[96] Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39,984, 39,985–86 (Aug. 6, 1981).
[97] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941).
[98] *See, e.g.*, Department, Order No. 202-22-4 (Dec. 24, 2022) at 1 (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between December 23 and December 26); Department, Order No. 202-20-2 (Sept. 6, 2020) (responding to shortages produced by ongoing extreme heat and wildfires); *see also* Rolsma, 57 Conn. L. Rev. at 803-4 (describing "sparing[]" use of Section 202(c) outside of wartime shortages during the twentieth century).

Research Service, the orders issued by the Department in May 2025 (and subsequently renewed) to keep coal plants open "all involve[d] seemingly new interpretations of the emergency authority."[99] The Order at issue in this proceeding continues this improper use of Section 202(c).

Similarly, before 2025, the Department used Section 202(c) on only three occasions to delay the retirement of generation facilities.[100] Each case met the following four criteria: (1) the order was requested by a system operator or governmental body; (2) the generation facility had ceased or would soon cease operation due to an inability to comply with environmental laws; (3) the request aimed to address a concrete and particularized emergency threatening an imminent loss of load; and (4) the Department tailored its order to go no further than necessary to address the emergency.

[99] Cong. Research Serv., *Federal Power Act: The Department of Energy's Emergency Authority*, CRS Report No. R48568, at 3 (June 12, 2025).

[100] In 2005, the Department issued an order directing the continued operation of a facility in Alexandria, VA, after the facility was abruptly closed based on noncompliance with its air permit. The order only applied when one or both of the 230 kv transmission lines serving downtown D.C. were out of service. Department, Order No. 202-05-3 (Dec. 20, 2005). In 2017, an Oklahoma state agency asked the Department to direct the continued operation of a unit that would otherwise close because the unit was needed to provide dynamic reactive power support to the local grid, as confirmed by its reliability coordinator. The unit was needed because another unit at the station had been struck by lightning, and the third unit's construction had been delayed due to flooding delaying essential project materials. The Department subsequently ordered the unit to remain in operation for 90 days or until one of the other two units came online, to provide dynamic reactive power support when called upon by its reliability coordinator. Department, Order No. 202-17-1 (Apr. 14, 2017). Finally, in 2017, two Virginia utilities asked the Department to direct the continued operation of two units of a power station because they were necessary to prevent uncontrolled power disruptions and shedding of critical load. Letter from PJM Interconnection, LLC, to the Department (Aug. 24, 2017).

The Department's unexplained deviation from its prior interpretation of the statute, as demonstrated through its past practice, is unlawful, arbitrary and capricious.[101] And the Department cannot deviate from its regulations without conducting new notice and comment rulemaking and providing a reasonable basis for any change.[102] A cornerstone of administrative law is "that an agency must provide[ ] a reasoned explanation for departing from precedent or treating similar situations differently."[103] For this reason, "an interpretation of a legislative rule cannot be modified without the notice and comment procedure that would be required to change the underlying regulation—otherwise, an agency could easily evade notice and comment requirements by amending a rule under the guise of reinterpreting it."[104] The Department has not undertaken any such notice and comment procedure here and has not provided any reasoned justification for its recent departure from the binding requirements and interpretations of its governing statute and regulations.

iv. Courts have found that the Department's use of Section 202(c) is limited to true emergencies and the Department is bound by the courts' statutory interpretation.

There is little case law on Section 202(c). However, two decisions that have addressed the Department's authority under Section 202(c) both recognize that the

[101] *F.C.C. v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009) ("To be sure, the requirement that an agency provide reasoned explanation for its action would ordinarily demand that it display awareness that it *is* changing position.").
[102] *See* 5 U.S.C. § 553; *F.C.C.,* 566 U.S. at 515 (holding that an agency cannot simply change position on an issue without "a reasoned explanation" and "awareness that it is changing position.").
[103] *New England Power Generators Ass., Inc. v. FERC*, 881 F.3d 202, 210–12 (D.C. Cir. 2018) (quoting *W. Deptford Energy, LLC v. FERC*, 766 F.3d 10, 20 (D.C. Cir. 2014)).
[104] *Env't Integrity Project v. EPA,* 425 F.3d 992, 995 (D.C. Cir. 2005) (internal citations omitted); *see also Center for Biological Diversity v. Haaland*, 998 F.3d 1061, 1067 (9th Cir. 2021) (internal citations omitted) ("When an agency changes its position, it must: (1) "display [ ] awareness that it is changing position," (2) "show "the new policy is permissible under the statute," (3) "believe[ ]" the new policy is better, and (4) provide "good reasons" for the new policy.").

Department's power under Section 202(c) is limited to specific, imminent, unexpected and temporary events.

First, during the 1973 oil embargo, the Federal Power Commission called for a voluntary transfer of electricity from non-oil power plants to areas of the country that relied heavily on oil, but the New England Power Pool petitioned for a Section 202(c) order because it was not convinced the voluntary program would work.[105] The Commission declined to issue a Section 202(c) order, and instead facilitated an agreement between state commissions and supplying utilities.[106] In *Richmond Power and Light of City of Richmond, Indiana v. FERC*, the D.C. Circuit upheld the Commission's decision to not invoke Section 202(c).[107] The utility argued that the country's dependence on foreign oil, and the high cost and uncertain supply of foreign oil, left the country with a continuing emergency, but the court agreed with the Commission's argument that the facilitated agreement had worked, service was never interrupted, and there was no need for a Section 202(c) order.[108] The court highlighted that the statute "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply[.]"[109] The court upheld the Commission's view that Section 202(c) cannot be used when "supply is adequate but a means of fueling its production is in disfavor."[110]

[105] *Richmond Power & Light*, 574 F.2d at 613.
[106] *Id*.
[107] *Id.* at 614.
[108] *Id.* at 615.
[109] *Id*.
[110] *Id.*

The Eighth Circuit Court of Appeals has also held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power Co. v. Fed. Power Comm'n*., a utility insisted a Section 202(c) order was necessary to properly order the utility to connect to a municipal power provider. The demand for electricity in the city had increased, and the peak load of the municipal power provider was high enough that both of its two generators would likely be needed simultaneously in the near future, which could cause a possible loss of service if one of them malfunctioned during a peak period.[111] Instead of issuing a 202(c) order, the Commission issued an order under Section 202(b), which the utility argued was incorrect.[112]

In upholding the Commission's decision, the court distinguished between an emergency that is likely to occur and one that is actually occurring, concluding that Section 202(b) applies to the former, while Section 202(c) applies to the latter:

> On its face, § 202(c) enables the Commission to react to a war or national disaster and order immediate interconnection of the facilities to maintain electrical service during such emergency. . . On the other hand, § 202(b) applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission.[113]

Therefore, the court agreed that a potential crisis in the foreseeable future was not an emergency, making this current situation "just the type of situation to fit into a § 202(b) hearing rather than § 202(c)."[114]

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[111] *Otter Tail Power*, 429 F.2d at 233-234.
[112] *Id*.
[113] *Id*. at 234.
[114] *Id.*

Because courts, not agencies, decide "all relevant questions of law" arising on review of agency actions, the Department is bound by these courts' "best reading" of the statutory language.[115]

B. Section 202(c) does not vest the Department with general regulatory authority over resource adequacy, which is regulated by the states and FERC under other provisions of the FPA.

The FPA preserves states' authority over generation facilities and resource adequacy planning, and Section 202(c) does not vest the Department with general regulatory authority over resource adequacy. Under the FPA, states are responsible for their own resource adequacy and decisions about generation facilities, and FERC is responsible for assuring the reliability of the nation's bulk power system. Because there is no imminent shortfall or other circumstance constituting an emergency, the Order is an illegal attempt to regulate long term resource adequacy by misusing the Department's Section 202(c) authority.

i. The FPA grants authority over generation and resource adequacy to the states.

The structure and language of the FPA reflect Congress' deliberate choice to preserve the states' traditional authority over generating facilities and to limit the Department's emergency authority. The FPA states that "the Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy…"[116] Congress also recognized the states' exclusive authority over generating

[115] *Loper Bright Enterprises v. Raimondo*, 603 U.S. 369, 392, 399-400 (2024).
[116] 16 U.S.C. § 824(b)(1).

facilities in Section 202(b), which provides that FERC's interconnection authority does not include the power to "compel the enlargement of generating facilities for such purposes."[117] FERC's role in regulating electricity generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the States."[118]

Pursuant to the FPA, "[t]he states are thus authorized to regulate energy production . . . and facilities used for the generation of electric energy."[119] Decisions around what facilities to build, whether they remain feasible, and retail rates are areas governed by the states.[120] Courts have held that Section 201(b)(1) reserves to the states authority over electric generating facilities, including that states retain the right "to require the retirement of existing generators" or to take any other action in their "role as regulators of generation facilities."[121] FERC has acknowledged that "[r]esource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsive for procuring adequate capacity to serve loads within their respective jurisdictions."[122]

The electric power sector is governed by longstanding principles of cooperative federalism encouraged in Section 209(b) of the FPA, which explicitly declares that FERC may consult with states "regarding the relationship between rate structures,

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[117] 16 U.S.C. § 824a(b).
[118] 16 U.S.C. § 824(a).
[119] *Coal. for Competitive Elec.,* 906 F.3d at 50.
[120] *Pac. Gas & Elec. Co. v. State Energy Res. Conservation and Dev. Comm'n*, 461 U.S. 190, 205 (1983).
[121] *Conn. Dep't of Pub. Util.*, 569 F.3d at 481; *see also Hughes*, 578 U.S. at 155.
[122] *Devon Power LLC, et al.*, 109 FERC ¶ 61,154, P 47 (2004).

costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction of such State commission and of the Commission."[123] FERC has embraced these cooperative federalism principles and developed long-standing consultation practices with the states, including through creation of a Joint Federal-State Task Force,[124] and more recently, a Federal-State Current Issues Collaborative which was formed due to the success of the Task Force.[125] The importance of this cooperation is evident in the Department's own Resource Adequacy Report, which flagged that it could have benefitted greatly from cooperation with the states due to the "in-depth engineering assessments which occur at the regional and utility level."[126]

In the Order, the Department seeks to substitute its own judgment about which resources should be employed to maintain resource adequacy for the states' decisions, despite these decisions resting firmly in the jurisdiction of the states. Section 202(c) does not provide the Department with the authority to mandate that resources remain running to address long-term resource adequacy. If Congress intended to vest regulatory authority over long-term resource adequacy in Section 202(c) and displace state law, it would have needed to make that intent "unmistakably clear."[127] Section 202(c) says that the Department may "require by

[123] 16 U.S.C. § 824h(b).
[124] FERC, *Joint Federal-State Task Force on Electric Transmission* (Sept. 3, 2025).
[125] FERC, *Federal-State Current Issues Collaborative* (Jan. 21, 2026).
[126] Department, *Resource Adequacy Report Evaluating the Reliability and Security of the United States Electric Grid* (July 2025) at 2.
[127] *Gregory v. Ashcroft,* 501 U.S. 452, 460 (1991) (The clear statement rule requires Congress to make its intent unmistakably clear if it intends a statute to alter the usual constitutional balance between the federal government and the states.); *see also DeMarco v. Holy Cross High Sch.*, 4 F.3d 166, 169 (2d Cir. 1993) (Congress must express an affirmative intention to use a statute to alter the federal balance.).

order . . . such generation . . . of electric energy as in its judgment will best meet the emergency and serve the public interest."[128] Empowering the Department to generally determine which power plants may retire across every utility and independent power producer across the entire country would have profound implications for rates, state sovereignty, and a broad array of other state policy and stakeholder interests. If Congress had intended to do that, it would not have done so through the only provision in the FPA that empowers the Department to act outside normal procedural safeguards.

The Supreme Court has rejected statutory interpretations where an agency "claim[s] to discover in a long-extant statute an unheralded power representing a transformative expansion in its regulatory authority."[129] The Department may not radically reinterpret a 90-year-old statute to manufacture a basis to exercise much broader authority than it ever has in the past. Previous exercises of Section 202(c) authority have been at the request of a system operator or governmental body and in a manner narrowly tailored to respond to a concrete and particularized emergency. Prior to the current administration, the Department has never issued a Section 202(c) order to impose its policy preferences to contravene the judgment of those bodies properly responsible for ensuring resource adequacy, *i.e.*, the states and FERC. For these reasons, the Order should be withdrawn.

[128] 16 U.S.C. § 824a(c)(1).
[129] *W. Virginia v. EPA*, 597 U.S. 697, 724, (2022) (quoting *Util. Air. Regul. Grp. V. E.P.A.*, 573 U.S. 302, 324 (2014)) (internal quotations omitted).

ii. The Order improperly infringes on authority granted to states and FERC under the FPA by attempting to regulate long-term resource adequacy and generation.

The Department is attempting to regulate long term resource adequacy and energy production under the guise of a Section 202(c) emergency, and is therefore intruding on the FERC and state authority discussed above.

It is clear from the Order, the Department's Resource Adequacy Report, and statements by President Trump, and the Department, that the Department is using its Section 202(c) authority for circumstances beyond actual emergencies. The Order repeatedly references long term reliability. For example, the Department's determination that an emergency exists rests on the assertion of a long term concern that "increasing demand and shortage from accelerated retirement of generation facilities . . . could lead to the loss of power to homes, and businesses" that are "likely to continue in subsequent years."[130] The Order also cites the LTRA's statement regarding resource retirements between now and 2028, that WECC's Northwest-Central subregion will have demand growth over the next decade, and that Colorado will have a certain amount of coal-fired generating capacity retired by 2029.[131] Demand growth and retirements occurring over the next decade fall into the realm of long term resource planning, not an imminent Section 202(c) emergency, which must be unexpected, sudden, and temporary.[132]

[130] Exhibit A at 3.
[131] *Id.,* at 2.
[132] Section V.A, supra.

Both the Department and President Trump have publicly acknowledged that their goal is to regulate long term resource adequacy and mandate coal generation. the Department Secretary Wright has stated that "[t]he goal [of the recent 202(c) orders] is to stop the political closure of coal plants."[133] The "Clean Beautiful Coal" Executive Order directed the Department to "identify regions where coal-powered infrastructure is available and suitable for supporting AI Data centers; assess the market, legal and technological potential for expanding coal-based infrastructure to power data centers to meet the electricity needs of AI…"[134] These statements demonstrate a clear intention to use coal plants to meet long term resource adequacy needs, which exceeds the Department's Section 202(c) emergency authority.

C. The Order fails to present substantial evidence for its emergency determination and ignores critical facts.

Agencies "must examine the relevant data and articulate a satisfactory explanation for [their] actions, including a rational connection between the facts found and the choice made[,]" and make findings that are supported by substantial evidence.[135] Substantial evidence is "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion."[136] Similarly, orders under the FPA must reflect "a principled and reasoned decision supported by the evidentiary record."[137] Here, the Department failed to provide evidence of an imminent resource

[133] Department, *Energy Department Convenes First National Coal Council Meeting Under Renewed Charter, Reaffirming Coal's Role in Unleashing American Energy* (Jan. 15, 2026).
[134] Exec. Order No. 14241, 90 Fed. Reg. 15,517 (Apr. 14, 2025).
[135] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (quoting *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962)).
[136] *Chritton*, 888 F.2d at 856 (quoting Refrigerated Transport Co., Inc. v. I.C.C., 616 F.2d 748, 751 (5th Cir.1980) (quoting Chem–Haulers, Inc. v. United States, 536 F.2d 610, 617 (5th Cir.1976)).
[137] *Emera Maine*, 854 F.3d at 22.

adequacy shortfall, making the Order contrary to law. The purported evidence of an emergency the Order cites is: the 2024 LTRA, WECC's Western Assessment of Resource Adequacy, and the Department's Resource Adequacy Report; general load growth in the WECC-Northwest region and generation retirement in Colorado; the Grid Reliability and Energy Emergency Executive Orders; and data center load growth. Contrary to the Order's claims, these reports and observations do not provide sufficient evidence of an energy emergency in the WECC-Northwest region or the areas served by Craig Unit 1.

i. NERC's assessments do not establish that there is an energy emergency in the areas served by Craig Unit 1.

The Order cites the NERC 2024 LTRA's statement that energy variability is greater in the Northwest than other regions, and that the WECC-Northwest assessment area anticipates baseload resource retirements to be primarily replaced by solar, wind, and battery, which increases variability and implicates some supply chain concerns.[138] The Order relies on these statements to assert the WECC-Northwest assessment area is experiencing an energy emergency. This both mischaracterizes the 2024 LTRA's conclusions and ignores more relevant and recent NERC assessments. By failing to consider relevant facts and to support its findings with substantial evidence, the Department's Order is contrary to law.

The Department's choice to rely on the 2024 LTRA as evidence of an emergency is fundamentally flawed. NERC serves an important advisory role by providing recommendations about risks to the grid, but ultimately, determinations

[138] Exhibit A.

about generation resources remain within state authority.[139] Importantly, NERC's reports do not examine regions at the level of granularity that would be required to determine whether a particular resource is essential for regional resource adequacy. The reports only provide the anticipated planning reserve margins of large regions as a whole. The purpose of NERC assessments are to identify for grid operators constraints that might arise and implicate grid reliability if not mitigated.[140] Thus, even regions designated as at risk are not necessarily grid emergencies, they are merely periods of time during which the relevant grid operators must take mitigation measures to maintain grid security, under their set procedures. In addition, the 2024 LTRA was published more than a year ago and relies on data almost two years old. It assesses the adequacy of planned resources to meet electricity demand across North America over the next ten years.[141] The 2024 LTRA does not address short-term reliability issues. Therefore, this report cannot support a decision by the Department to keep one power plant open in the name of a general region-wide emergency.

Even if it was an appropriate assessment for the Department to rely upon, the 2024 LTRA does not actually demonstrate an emergency for the WECC-Northwest assessment area, contrary to the Order's claims. The Order cherry picks certain information from the 2024 LTRA: citing its statement that the WECC-Northwest assessment area anticipates retiring 5 Gigawatt ("GW") of baseload resource retirements between 2024 and 2028, which will be replaced by solar, wind, and

[139] NERC, *Reliability Assessments* (2026).
[140] Exhibit L.
[141] Exhibit K.

batteries, and that supply chain issues preventing the construction of battery systems are a concern. The Order conveniently ignores the 2024 LTRA's entire analysis of the WECC-Northwest assessment area's forecasted resource adequacy, and its calculation that the WECC-Northwest has anticipated reserve margins (when including announced generation retirements) of 38.9% for 2026, 35.6% for 2027, and 30.7% for 2028.[142] The 2024 LTRA found that the WECC-Northwest region has "negligible unserved energy and load-loss risk."[143]

Although the 2024 LTRA identified a potential shortfall starting in summer 2029, this potential shortfall was projected only if new resources planned in the region were "significantly delayed," in which case "imports may be necessary."[144] A potential shortfall starting over three years from now—and only if planned resources are significantly delayed—does not provide sufficient evidence to support an emergency declaration for the 90 days covered by the Order. And even if "significant delays" create risk in summer 2029, the 2024 LTRA suggests that imported power will be sufficient to cover any shortfall, once again undermining any case for mandating continued operation of a single generating unit.

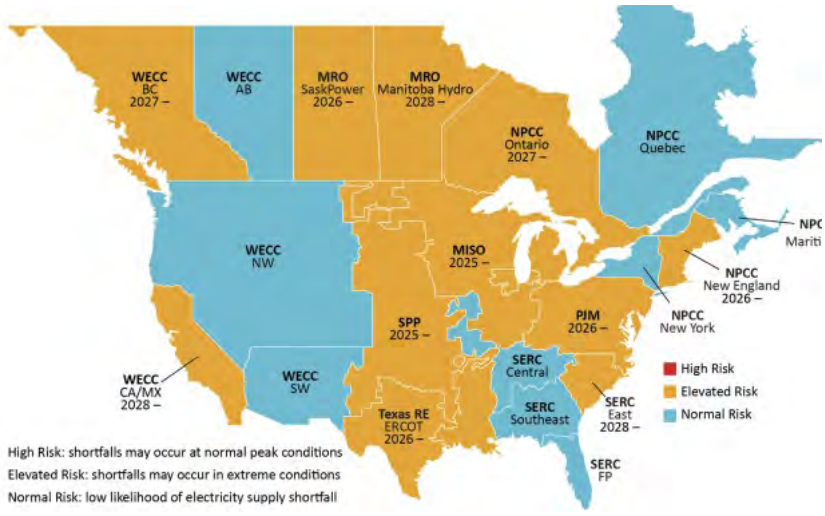
The 2024 LTRA also found that the WECC-Southwest region, which includes Arizona, has anticipated reserve margins (when including announced generation retirements) of 35.6% for 2026 and 31.6% for 2027.[145] The WECC-Southwest region does not show any shortfall of existing certain and net firm transfers until 2028, when

[142] *Id.,* at 20.
[143] *Id.,* at 129.
[144] *Id.*
[145] *Id.,* at 20.

imports may become necessary, but only if new resources were significantly delayed.[146]

As shown in the figure below, WECC-Northwest and WECC-Southwest, which covers all the states served by Craig Unit 1, are designated as normal risk, which means a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low.[147]

Figure 1: 2024 LTRA Risk Area Summary 2025-2029[148]



Next, the Order completely fails to acknowledge the two more recent short-term reliability assessments, the 2025-2026 WRA and the 2025 SRA, which evaluate overall operating reliability for the assessed regions on a seasonal basis and account for near-term resource availability impacts such as outages on the peak operating periods for the summer and winter.[149] The 2025-2026 WRA is NERC's most recently

[146] *Id.*, at 132.
[147] *Id.*, at 6.
[148] *Id.*, at 6.
[149] NERC, *ERO Enterprise Reliability Assessment Process Document* (Jan. 2024).

published report and covers the current three-month winter period (December 2025-February 2026)—approximately the same time period covered by the Order. It evaluates the generation resource and transmission system adequacy necessary to meet projected demands and operating reserves and identifies potential reliability issues of interest and regional risk.

The Department's reliance on the 2024 LTRA is also problematic because NERC changed the geographic scope assessment areas for the 2025 SRA and 2025-2026 WRA. The 2024 LTRA includes Colorado, Utah, and Wyoming in the WECC-Northwest assessment area, and Arizona is in the WECC-Southwest assessment area.[150] Since the Order is issued to Craig Unit 1 in Colorado, and only references the LTRA and the WECC-Northwest area, it appears the Order is relying on the 2024 LTRA's scope of the WECC-Northwest area. Importantly, the 2025 SRA and 2025-2026 WRA do not include any of the states served by Craig Unit 1 in the WECC-Northwest. For these assessments, the WECC-Rocky Mountain area, not the WECC-Northwest area, includes Colorado and most of Wyoming, WECC-Southwest includes Arizona, and WECC-Basin includes Utah and the rest of Wyoming.[151] The Order ignores that NERC changed the assessment areas used in the 2024 LTRA to "more accurately reflect operational and planning realities, as well as the footprints of various entities[,]"[152] and instead refers to the outdated regions used in the 2024 LTRA. The Department should reconsider the

[150] Exhibit K at 127, 131.
[151] NERC, *2025 SRA* (May 2025), at 36.
[152] WECC, *2025-2026 WRA Western Overview*.

Order because the scope of the declared emergency does not match the assessment area.[153]

The 2025-2026 WRA found that "all assessed areas have adequate resources for normal winter peak load conditions."[154] WECC-Rocky Mountain, which includes Colorado and most of Wyoming, and WECC-Southwest, which includes Arizona, were not found to be at risk of electricity supply shortfalls even in more extreme winter conditions extending over a wide area.[155]

Figure 2: 2025-2026 WRA Winter Reliability Risk Area Summary[156]



[153] The mismatch between the assessment area and the scope of the purported emergency will also complicate operations and cost recovery actions. Because Craig Unit 1 does not serve the majority of states in the WECC-Northwest assessment area, it is unclear how Craig Unit 1 could be operated to meet an emergency in that area, and unclear which ratepayers should be responsible for the costs of any such operations. Colorado does not concede that Colorado ratepayers should be responsible for these costs.
[154] Exhibit L at 5.
[155] *Id.*, at 5.
[156] *Id.*, at 6.

According to the 2025-2026 WRA, the WECC-Rocky Mountain area will **not** need to rely on imports to maintain resource adequacy even under combined extreme peak and extreme derated conditions, and operating reserve margins are expected to be met before needing imports in all winter scenarios.[157] The region has an anticipated total internal demand of 11,501 MW, and 17,768 MW of certain capacity, which does not include planned capacity and anticipated resources.[158] This leaves an anticipated reserve margin of a staggering 61.7%, which is over triple the reference margin level of 18.2%.[159] By contrast, Craig Unit 1 could provide a maximum of 222 MW to the WECC-Rocky Mountain area, which would have a negligible impact on the already high anticipated reserve margin.

The 2025-2026 WRA also expects WECC-Southwest to be resource adequate under all winter expected and extreme energy availability and demand scenarios before needing imports.[160] WECC-Southwest has a total demand of 21,147 MW and a certain capacity of 40,135 MW before accounting for planned capacity and anticipated resources.[161] This leaves an anticipated reserve margin of 104.4%.[162]

WECC-Basin (which includes Utah, where PacifiCorp owns a mere 19% of Craig Unit 1, or 82 MW of the unit's total capacity) has sufficient capacity for expected peak conditions and an anticipated reserve margin of 29.6% for this season.[163] This means that expected resources meet operating reserve requirements under normal

[157] *Id.,* at 38.
[158] *Id.,* at 49.
[159] *Id.*
[160] *Id.,* at 39.
[161] *Id.,* at 49.
[162] *Id.*
[163] *Id.*, at 6, 48.

peak demand scenarios. The WECC-Basin region is designated as "elevated risk" in the 2025-2026 WRA because it would require external assistance only during a combination of above normal peak demand and high generator outages in extreme conditions.[164] However, a designation of "elevated risk" does not constitute an imminent emergency. Rather, the WRA concludes that "the results of the probabilistic assessment reveal no [Expected Unserved Energy] or [Loss of Load Hours] for Winter 2025– 2026."[165]

Consistent with this assessment, none of the Craig Unit 1 Owners has indicated that they need Craig Unit 1 to mitigate any resource adequacy concerns this winter. None of the NERC assessments, whether cited by the Order or not, provide substantial evidence of an energy emergency in the WECC-Northwest region.

ii. WECC's Western Assessment of Resource Adequacy and the Department's Resource Adequacy Report do not demonstrate an emergency.

The Order also cites the 2024 WECC Western Assessment of Resource Adequacy ("2024 WECC Assessment") to support its declaration of an emergency. Like the 2024 LTRA that the Order cites, the 2024 WECC Assessment does not analyze near-term resource adequacy, and instead uses a probabilistic approach to evaluate reliability over the next ten years.[166] This makes the 2024 WECC Assessment inappropriate for providing evidence of an emergency under Section 202(c).

[164] *Id.,* at 6.
[165] *Id.,* Table 5: Probability-Based Risk Assessment, at 14 (emphasis added).
[166] WARA, *Western Assessment of Resource Adequacy 2024*.

Even if the 2024 WECC Assessment was appropriate evidence for the Department to rely upon, it does not demonstrate an emergency in the areas served by Craig Unit 1. Once again, the Department selectively cites information in that report showing that peak demand is expected to grow and that there are planned baseload generation retirements, but ignores that this assessment finds no near-term energy emergency in any of WECC's regions. [167] In fact, the 2024 WECC Assessment finds that entities in the Western Interconnection plan to add more than 172 GW of new generation capacity in the next ten years, while a mere 25.85 GW of generation is planned to retire over the same period.[168] WECC's Northwest-Central subregion, which includes Colorado, whose load growth the Order specifically mentions, does not have demand at risk hours until 2031, and then only in a scenario where merely 55% of planned additions are completed and operational on time.[169] The 2024 WECC Assessment does not provide substantial evidence of an emergency in the areas served by Craig Unit 1.

Next, the Order briefly references the Department's Resource Adequacy Report,[170] which purports to provide a uniform methodology for identifying at-risk regions and grid reliability issues and guide reliability interventions. As with other reports cited in the Order, this Report provides no support for the Department's determination that there is an emergency requiring continued availability of Craig Unit 1 in the next 90 days, or even the next year. The Report assesses the ability of

[167] Exhibit A, at 2.
[168] WARA, *Western Assessment of Resource Adequacy 2024*.
[169] *Id.*
[170] Exhibit M.

the electric grid to "meet *future* demand through 2030" and is a "*forward-looking* snapshot of resource adequacy."[171] This Report was not designed to assess imminent emergency conditions of the electric grid, and explicitly does not do so.

Indeed, the Report's only conclusions are for 2030, which is completely irrelevant for an emergency Section 202(c) order issued in 2025. The Report finds potential reliability issues in 2030 only under a set of unsupported assumptions that assume unrealistically high load projections stemming from unfounded assumptions about data center load, and assume that utilities virtually cease construction of new generation and transmission resources. Its 2030 projections are at odds with the analyses from NERC and WECC, as well as the findings from Colorado's ERP proceedings and resource adequacy reporting. In any case, a claimed reliability issue in 2030 can not justify a 90 day emergency order in 2026. Forcing ratepayers to pay to keep generation online that is not needed, simply because technology companies may be building more data centers in the future that may need power is arbitrary and violates the FPA's requirement that rates be just and reasonable, especially as other analyses indicate that data center projections may be overblown.[172]

Given its focus on future conditions and unverified assumptions, the Report is not substantial evidence of an emergency under Section 202(c).

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[171] Department, *Resource Adequacy Report Evaluating the Reliability and Security of the United States Electric Grid* (July 2025) at 9 (emphasis added).

[172] Exhibit SS (Behr, P., *PJM to ratchet down projected AI power demand for eastern US* (Jan. 6 , 2026)); Institute for Policy Integrity, *Fiscal Year 2025 Annual Report*; London Economics International LLC, *Uncertainty and Upward Bias are Inherent in Data center Electricity Demand Projections* (July 7, 2025).

iii. State planning processes have assured that the areas served by Craig Unit 1 have sufficient capacity currently and will continue to have sufficient capacity without Craig Unit 1.

The Order notes that Colorado has retired 571.3 MW of coal generating capacity since 2019. However, the Order does not provide any evidence that these retirements have resulted in a resource shortfall in Colorado. The Order also ignores the rest of the states that are served by Craig Unit 1. All five of the Craig Unit 1 Owners' service areas have sufficient capacity for 2026-2030, well beyond the 90 day period covered by the Order, and do not need energy from Craig Unit 1 to maintain resource adequacy or reliability. Pursuant to the authority reserved to the states by the FPA, Colorado, Arizona, Wyoming, and Utah have robust electric resource planning processes that ensure resource adequacy and grid reliability. None of these states are currently part of an RTO or ISO, and therefore their electric grid is mainly managed by individual utilities and overseen by states and balancing authorities.

a. Colorado's robust planning process ensures sufficient capacity for the State's utility customers.

For decades, Colorado has implemented robust and successful electric resource planning processes that serve as a model for other states. Colorado's process assesses resource adequacy and reliability across utilities' service territories, requires regulated utilities to use competitive resource solicitations to acquire new resources of multiple fuel types, and ensures that there will be sufficient electricity to meet expected load, even with planned plant closures.[173]

[173] Exhibit C.

As part of Colorado's overall energy planning framework, each investor-owned retail electric utility and wholesale electric generation and transmission cooperative is required to submit to the CoPUC an application for approval of an ERP.[174] Each Colorado ERP proceeding thoroughly considers resource adequacy and reliability at multiple stages.[175] In developing their forecasted resource needs, utilities' electric energy and demand forecasts must be completed for each year within the ERP planning period and must include, among other components, the electric demand placed on the utility's system for each hour of the day for peak-day, average-day, and representative off-peak days for each calendar month.[176] Utilities must "develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period[,] . . . . including base case, high, and low" demand growth scenarios.[177] Since the announcement of Craig Unit 1's retirement in 2016, the CoPUC has received annual resource planning reports from Tri-State and Public Service, and has conducted two adjudicated resource planning proceedings for Tri-State's system and three for Public Service's system, with administrative records totaling in the tens of thousands or hundreds of thousands of pages. All of these proceedings have included the planned Craig Unit 1 retirement as a foundational assumption in forecasting, modeling, and portfolio selection.

[174] § 40-2-125.5, Colo. Rev. Stat.; 4 Colo. Code Regs. §§ 723-3-3603(a), -3605(a).
[175] Exhibit C.
[176] 4 Colo. Code Regs. § 723-3-3605(b).
[177] *Id.* at -(b)(II).

In an ERP proceeding, the utility must describe and justify the means by which it assesses the desired level of system reliability, and it must propose target planning reserve margins for each forecasted scenario.[178] Utilities' planning reserve margin studies employ probabilistic modeling to determine the amount of capacity necessary to maintain a certain level of reliability, for example a Loss of Load Expectation of 0.1 days/year. The studies must account for a wide variety of risks, "includ[ing] risks associated with: the development of generation; losses of generation capacity . . . ., losses of transmission capability; [and] risks due to known or reasonably expected changes in environmental regulatory requirements[.][179] Planning reserve margin studies also rely on thorough analyses, for each resource type, of the Effective Load Carrying Capability ("ELCC"), or the amount of dependable capacity that can be counted on by the system for resource adequacy purposes.[180] Utilities are also required to present contingency plans for the acquisition of additional resources in the event demand increases or expected generation resources are not developed.[181] Following extensive stakeholder input and vetting through rounds of testimony and cross-examination of utility's need for additional generation to be acquired through an all-source competitive resource solicitation.[182] The additional generation must be able to meet system needs, including availability or dispatchability at certain hours of the day.[183]

[178] 4 Colo. Code Regs. § 723-3-3605(e).
[179] *Id*. at -(e)(II).
[180] Exhibit C.
[181] 4 Colo. Code Regs. § 723-3-3605(e)(III).
[182] Exhibit C.
[183] *Id.*

Upon completion of a resource solicitation, the utility presents a number of potential resource portfolios. Included in this presentation are the results of additional reliability checks, which further ensure resource adequacy and reliability by demonstrating that each portfolio satisfies relevant metrics such as meeting the required planning reserve margin, meeting a Loss of Load Hours target and meeting an Annual Expected Unserved Energy target.[184] After opportunities for stakeholder input, the CoPUC issues a decision establishing the final cost-effective resource plan. In making this decision the CoPUC considers various statutory factors, including whether the resource plan meets the energy policy goals of Colorado, such as giving full consideration to cost-effective resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.[185]

b. Tri-State's ERP demonstrates a reliable resource portfolio after Craig Unit 1's retirement.

Tri-State's most recent electric resource proceeding[186] concluded in August 2025 with the selection of Tri-State's preferred resource portfolio as the approved cost effective resource plan.[187] The portfolio includes the addition of 700 MW of wind and solar, 650 MW of storage, and 307 MW of gas between 2026-2031, replaces the turbines on one of Tri-State's gas plants to improve its capacity contributions, and maintains the retirement dates of three coal plants (including Craig Unit 1).[188] Tri-

[184] *E.g.*, Exhibit J, at 94-95.
[185] 4 Colo. Code Regs. § 723-3-3605(h); § 40-2-134, Colo. Rev. Stat.
[186] Tri-State's planning processes encompass all states in its service territory, including Wyoming and Colorado. *See* Exhibit X, at 6.
[187] Exhibit E, ¶ 90.
[188] Exhibit X, at 6.

State demonstrated that the portfolio meets all reliability metrics, and avoids costly transmission upgrades required by other analyzed portfolios.[189] Tri-State remains in a capacity-long position until 2030 but has planned on the above resource acquisitions to ensure reliability as its coal units retire in 2025, 2028, and 2030 and to maintain progress toward emissions reductions.[190]

Tri-State supported each of the considered resource portfolios with two levels of rigorous reliability metric checks. The first level, intended to meet industry standards, required each portfolio's satisfaction of: (1) the target planning reserve margin for each year in the resource acquisition period, or 22% transitioning to 30.5% in 2028; (2) a Loss of Load Hours maximum of 1 day in 10 years and a maximum of 2.4 hours annually; and (3) an Expected Unserved Energy maximum of less than or equal to 0.4 Gigawatt hours ("GWh") annually.[191] The second level of reliability metrics was applied to the extreme weather event sensitivities to ensure reliable service during likely future weather events, and required that this modeled sensitivity for each portfolio resulted in: (1) no more than 12 hours of expected unserved energy during all extreme weather events modeled in the years 2026-2031; (2) no more than 3 Loss of Load Hours per each year in the years 2026-2031; (3) and an Expected Unserved Energy maximum of 20% of load in any hour.[192] Tri-State demonstrated that each presented resource portfolio met these reliability metrics. For the portfolio approved by the CoPUC, planning reserve margins ranged from 24% in 2025 to 34% in 2031, with

[189] Exhibit J.
[190] Exhibit W (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E), at 30:15-16.
[191] Exhibit J, at 18.
[192] *Id.*; Exhibit W.

zero Loss of Load Hours and zero annual expected unserved energy during that period.[193]

Tri-State initially proposed the planning reserve margin targets satisfied by each portfolio through a detailed analysis of grid parameters, including the reliability needs of a system transitioning away from coal generation and toward increased reliance on renewables. ELCCs were determined for each resource type to appropriately model each resource's capacity potential for the specifics of Tri-State's system, rather than relying on nameplate capacity.[194] Incorporating these ELCCs and the reliability standard of 0.1 Loss of Load Expectation, Tri-State proposed that after the retirement of the Craig Station and the departure of certain member loads in 2028, the target planning reserve margin be 30.5%, which is considerably higher than its existing and historic reserve margin.[195] These planning reserve margins were carried through to Tri-State's portfolio approved in August 2025.[196]

In summary, every portfolio that Tri-State modeled in its most recent ERP assumed the retirement of Craig Unit 1 at the end of 2025, and every modeled portfolio met all reliability metrics, including Tri-State's approved portfolio.[197] And as specifically found by the CoPUC in its decision approving Tri-State's preferred

[193] Exhibit J, at 62.
[194] Exhibit OO (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 – Attachment G-1 (Astrape Consulting, Reserve Margin and ELCC Study, Public (Aug. 2, 2023)), at 8.
[195] *Id.*
[196] Exhibit W, at 20:8-15; Exhibit E.
[197] Exhibit J, Table 7: Modeled Retirements (Portfolio 1 - NEE), at 21, Table 32: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 2 – NELG), at 35, Table 28: Modeled Retirements (Portfolio 2 – NELG), at 32, Table 49: Modeled Retirements (Portfolio 3 – FLEX), at 43, Table 70: Modeled Retirements (Portfolio 4 – FLEXSR), at 54, Table 91: Modeled Retirements (Portfolio 5 – NNG), at 75, Table 112: Modeled Retirements (Portfolio 6 – NNGSR), at 75.

portfolio, "Craig Unit 1 is not required for reliability or resource adequacy purposes based on the record in this ERP."[198] Tri-State's most recent ERP progress report, filed on December 1, 2025, confirms that it is progressing with contracting for its preferred portfolio resources, and using its updated load forecast, it does not forecast a capacity shortfall until 2035.[199]

c. Colorado's process allows the State to quickly address changes in resource needs.

Utilities must file annual progress reports on their efforts to implement approved plans and on their emerging resource needs, including an updated forecast, updated evaluations of planning reserve margins and contingency plans, and updated assessments of additional resource needs.[200] And importantly, Colorado's electric resource planning process also allows for the filing of interim ERPs and certificates of public convenience and necessity to fill generation needs not identified or fully satisfied by ERPs completed on the regular cadence.[201] This allows electric utilities and the State to quickly respond to changes in load or available resources.[202]

For example, Public Service filed a Just Transition Solicitation Plan, treated as an interim ERP, on October 15, 2024. The CoPUC issued a Phase 1 decision on November 6, 2025, that approved the Company's ERP and established a pathway for Public Service to acquire necessary generation and storage resources and reliably

[198] Exhibit E, ¶ 116.
[199] Exhibit Z (CoPUC, Tri-State, 2025 Annual Progress Report, filed on December 1, 2025, in Proceeding No. 23A-0585E), at 8, 10-11.
[200] 4 Colo. Code Regs. § 723-3-3618.
[201] 4 Colo. Code Regs. §§ 723-3-3603(a), 3605(a)(II); Exhibit C.
[202] *Id*.

serve existing and future customers.[203] Like Tri-State, Public Service has filed previous ERPs that all accounted for the retirement of Craig Unit 1.[204]

Public Service has not indicated a need for energy from Craig Unit 1 to meet any immediate or longer-term resource needs. Public Service's ERPs demonstrate it is not anticipated to have a shortfall in the next 90 days, as Public Service is a summer peaking system. In recent filings before the CoPUC, Public Service raised some concerns for the summers of 2026 and 2027, which do not begin for another six months. Colorado is already acting to address Public Service's concerns. In December 2025, the CoPUC approved an extension of the retirement date for a Public Service coal plant located in Pueblo, finding that the delay of the planned Comanche Unit 2 retirement date until December 31, 2026, is necessary due to the unplanned outage of another coal unit, Comanche Unit 3.[205] Public Service is also engaging in a near-term procurement process within an older ERP proceeding to acquire additional resources to be deployed prior to 2031.[206] Thus, Colorado has flexible procedures that assure resource adequacy in the State, even when there are unforeseen events.

[203] CoPUC, Decision No. C25-0747, issued on November 6, 2025, in Proceeding No. 24A-0442E, ¶ 2.
[204] Exhibit C, ¶¶ 27-31.
[205] Exhibit BB, (CoPUC, Decision No. C25-0892, issued on December 10, 2020, in Proceeding No. 25V-0480E), ¶ 65. On November 10, 2025, the Colorado Energy Office, Trial Staff of the Public Utilities Commission, the Colorado Office of the Utility Consumer Advocate, and Public Service submitted a petition to the CoPUC requesting that a coal plant, Comanche Unit 2, which was also scheduled to retire on December 31, 2025, remain open for another year. *See* Exhibit Y (CoPUC, *Verified Petition of Trial Staff of the Commission, Colorado Energy Office, the Colorado Office of the Utility Consumer Advocate, and Public Service for a Variance from Decision No. C18-0761 and Any Other Requirements, Request for Shortened Notice and Intervention Period, and Request for Approval of Associated Procedures,* filed on November 10, 2025, in Proceeding No. 25V-0480E).
[206] Exhibit N.

PRPA, though not overseen by the CoPUC, develops an Integrated Resource Plan ("IRP") to conduct long-term resource planning and ensure resource adequacy.[207] PRPA ran all of its scenarios to meet a planning reserve margin of 19.9%.[208] With its current and committed resources, PRPA has enough capacity to maintain a 19.9% planning reserve margin through 2029.[209] PRPA began commercial operation of a 150 MW solar project in 2025,[210] plans to begin a 130 MW solar project in 2027, and is beginning processes to obtain additional dispatchable capacity.[211] PRPA has no resource adequacy issues now or forecasted upon the retirement of Craig Unit 1. As shown by its annual required filing with the Colorado Energy Office, its capacity well exceeds forecasted demand with a total accredited capacity of 885 MW and a native load forecast of 722 MW for 2026, leading to a planning reserve margin of 25.4%.[212] PRPA's General Manager and CEO has publicly stated that the utility does "not need the Craig 1 unit because it has already replaced the energy that came from it."[213]

d. The other states served by Craig Unit 1 also oversee resource planning to ensure reliability and adequate capacity.

Although the majority of Craig Unit 1's energy serves Colorado, and Colorado is the only state the Order specifically discusses, Utah and Arizona also receive energy from Craig Unit 1, through PacifiCorp and Arizona respectively. Each of these states has extensive resource planning processes.

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[207] Exhibit EE.
[208] *Id*.
[209] *Id*.
[210] PRPA, *Solar Energy* (2026).
[211] Exhibit EE, at 178.
[212] PRPA, *Worksheet Certification Form* (Apr. 28, 2025).
[213] Exhibit RR (Powell, R., *1 coal plant open amid order* (Jan. 6, 2026)) at 3.

The Utah Public Service Commission ("Utah PSC") has the power to supervise and regulate every public utility in Utah.[214] The Utah PSC regulates IRPs, including PacifiCorp's IRPs.[215] Utah utilities are also required to maintain a written reliability program.[216] PacifiCorp has a 2025 IRP that is specific to Utah, which Colorado understands to be the part of PacifiCorp's service territory that is sometimes served by Craig Unit 1's energy.[217] That IRP indicates that PacifiCorp expects to acquire 6,379 MW of new wind resources, 7,668 MW of storage resource, 5,492 MW of solar, and 500 MW of nuclear.[218] Currently, PacifiCorp owns 11,700 MWof generation capacity, meaning that its 82 MW from Craig Unit 1 makes up 0.7% of its generation capacity.[219] PacifiCorp acknowledges that coal resources have been an important resource in its portfolio in the past, but material changes in how PacifiCorp operates those assets has enabled the company to reduce fuel consumption and associated costs and emissions, and instead buy increasingly low cost zero emission renewable energy from market participants.[220] PacifiCorp is well above its winter system capacity planning reserve margin of 16.8% through 2028[221] and has expressed no need to keep Craig Unit 1 online.

[214] Utah Code Ann. § 54-4-S1 (2024).
[215] Utah Code Ann. § 54-17-301 (2025).
[216] Utah Admin. Code R746-313-4 (2025).
[217] Exhibit GG (PacifiCorp, *Utah Integrated Resource Plan Volume I* (Mar. 31, 2025)).
[218] *Id.* at 37.
[219] PacificCorp, *Powering a bright future* (2026).
[220] Exhibit GG.
[221] *Id.* at 265.

The Arizona Corporation Commission ("ACC") oversees the electric power industry in Arizona.[222] Load-serving entities, including Salt River Project, are required to annually file demand and supply side data, a forecast of peak load, and a 15-year resource plan that "[w]ill result in the load-serving entity's reliably serving the demand for electric energy services," with the ACC.[223] The Salt River Project conducts long-term resource planning to anticipate and meet future needs, most recently through their 2023 Integrated System Plan ("ISP"),[224] where the Salt River Project modeled multiple future scenarios to ensure that it would be resource adequate through 2035. The ISP plans for new resource acquisitions and accounts for all coal plant retirements. The ISP had all scenarios except two meet their requisite 16% planning reserve margin. The two scenarios that did not meet the PRM are more extreme scenarios where firm resource options are limited and there is accelerated load growth, but even in those two cases reliability would not be compromised until 2028.[225] Salt River Project did not pursue analysis of those scenarios, since they are not viable due to not achieving the planned reserve margin, even as far out as 2028.[226] Neither the ACC nor the Salt River Project have expressed concerns about resource adequacy and have been strategically planning for coal unit retirements. Salt River Project has construction "underway for 575 MW of new flexible natural gas resources . . . . and 55 MW of solar" and "is finalizing agreements for 480 MW of [additional] solar and 1300 MW of battery storage projects."[227] Further, Salt River Project receives its energy from Craig Unit 1 through an exchange with WAPA, where WAPA makes the necessary transmission available. However, that arrangement

terminates on April 1, 2026, and it is unclear how Salt River Project would get energy from Craig Unit 1 after that date.

The extensive planning processes conducted by the owners of Craig Unit 1 have ensured that the unit's retirement will not negatively impact the reliability of any of their electric grids. All of the utilities are resource adequate for the 90 days covered by the Order and none of them have expressed a need for Craig Unit 1.

e. FERC's oversight ensures reliability at the regional level.

In addition to these extensive state processes developed under the states' sovereign authority, the Craig Unit 1 Owners are all overseen by a variety of authorities, acting under FERC's delegated authority. As noted above, the FPA places this authority with FERC and does not provide any authority for oversight of long-term resource planning to the Department in Section 202(c). The FERC and state processes work together to ensure reliability, and the Order illegally intrudes on these processes without any reasonable basis.

The Order instructs Craig Unit 1 to be available to operate at the direction of SPP or WACM.[228] SPP is the reliability coordinator for Tri-State, PRPA, and Public Service.[229] SPP has been a reliability coordinator for over 20 years and has extensive operating criteria, outage coordination methodology, and emergency protocols.[230] SPP

[222] ACC, *Utilities Division*.
[223] Ariz. Admin. Code R14-2-703.F.2. (2025).
[224] Exhibit H.
[225] *Id.,* at 104-105.
[226] *Id.*
[227] SRP, *Integrated System Plan: ISP Actions Progress Report 2025* at 7.
[228] Exhibit A.
[229] SPP, *Western RC Services* (2026).
[230] SPP, *Operating Reliability* (2026).

has a Reliability Plan that details how it monitors for and responds to an emergency.[231] Like all Reliability Coordinators, SPP has "a wide-area view, operating tools, processes and procedures to prevent or mitigate emergency operating situations in next day analysis and real-time conditions[]" and has the authority to act and instruct its members to take actions to preserve the integrity and reliability of the bulk electric system.[232] Likewise, balancing authorities ensure that power system demand and supply are balanced and are responsible for maintaining operating conditions under mandatory NERC reliability standards.[233] WACM is a Balancing Authority overseen by SPP as a reliability coordinator.[234]

An energy emergency is defined by NERC and WECC as a situation when a load serving entity has exhausted all options for obtaining capacity and can no longer provide its customers with expected energy requirements.[235] A reliability coordinator will initiate an energy emergency alert at their own request, upon the request of a Balancing Authority, or upon the request of a load serving entity.[236] Reliability Coordinators and balancing authorities make the decision to call or request the calling

[231] Exhibit HH (SPP, *SPP Reliability Plan* (Jun 2, 2025)).
[232] *Id.,* at 6-7.
[233] Department, *Learning Series: Energy Security & Resilience*.
[234] SPP, *Western RC Services* (2026).
[235] WECC, *Standard EOP-002-2 - Capacity and Energy Emergencies* (2007).
[236] *Id.* At an Energy Emergency Alert Level 1, a Balancing Authority will call on all available power supplies, regardless of economics, including from other grids, and enable demand-side resource deployments.# At an Energy Emergency Alert Level 2, a Balancing Authority will initiate demand response programs that shed load from large industrial customers that have contractually agreed to do so and will publicly appeal to customers to cut back on electricity consumption.# If the highest level of emergency, Energy Emergency Alert Level 3, is called, then Reliability Coordinators will conduct emergency operating procedures to increase transfer capabilities into the entity declaring the emergency. NERC has general emergency operating instructions that address the effects of emergencies by ensuring each transmission operator and Balancing Authority has developed plans to mitigate operating emergencies and those plans are implemented and coordinated within the reliability coordinator. Exhibit II (NERC, Emergency Operations).

of an emergency pursuant to their emergency plans and operating procedures. WACM and SPP have not done so in this case, despite having the same (or likely more) information as the Department does about the reliability of the grid in the areas served by Craig Unit 1.

Therefore, if an emergency did occur in the areas served by Craig Unit 1 or in the WECC-Northwest assessment area, there are extensive procedures in place for that emergency to be handled by the complex and comprehensive network of the utilities themselves, Reliability Coordinators, and balancing authorities without the Department overstepping and preemptively trying to solve an emergency that has not occurred, and is not predicted to occur in any relevant assessment. The Order states merely that there is an emergency in the WECC-Northwest assessment area because of increasing peak demand and baseload generation retirements, without actually citing any reliability issues that have stemmed from those conditions. There is no evidence, and the Order cites none, that an emergency within the WECC system could not be handled by WECC's existing procedures and the existing mix of resources available in the region upon Craig Unit 1's retirement.

iv. The Executive Orders cited in the Order are not evidence of an energy emergency.

The Order also relies on the Energy Emergency and Grid Reliability Executive Orders as evidence of an energy emergency, generally stating that the Energy Emergency and Grid Reliability Executive Orders underscore the energy challenges facing the Nation due to growing resource adequacy concerns.[237] However, neither of

[237] Exhibit A.

these executive orders present evidence of an energy emergency in the WECC-Northwest Assessment Area or any other region of the county within the meaning of Section 202(c).[238]

On January 20, 2025, President Trump issued Executive Order 14156, *Declaring a National Energy Emergency* ("Energy Emergency Executive Order").[239] Despite its title, the Energy Emergency Executive Order fails to describe any type of energy emergency. It generically claims "[t]he energy … generation capacity of the United States [is] far too inadequate to meet our Nation's needs," and the situation "will dramatically deteriorate in the near future…"[240] The Energy Emergency Executive Order also specifically calls out the Northeast and West Coast states, claiming those states' "dangerous" "policies jeopardize our Nation's core national defense and security needs, and devastate the prosperity of not only local residents but the entire United States population."[241] The Executive Order does not identify any specific policies or explain how they are jeopardizing grid reliability.

President Trump then issued Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, ("Grid Reliability Executive Order") on April 8, 2025.[242] The Grid Executive Order also claims that the country is "experiencing an unprecedented surge in electricity demand," generically pointing to expansions of data centers and increases in domestic manufacturing as

[238] *See* 10 C.F.R. § 205.371 (defining emergency as a "specific inadequate power supply situation").
[239] Exec. Order 14156, 90 Fed. Reg. 8,433, 8,434 (Jan. 20, 2025).
[240] *Id.,* at Sec. 1.
[241] *Id.*, at 8,434.
[242] Exec. Order 14262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15,521 (April 14, 2025).

demand drivers.[243] These vague statements on nationwide energy needs are not sufficiently specific to justify a Section 202(c) order.

Neither of these Executive Orders provide data or other evidence in support of their claims of inadequate nationwide generation, let alone evidence of inadequate generation in the areas served by Craig Unit 1 such that they could constitute the evidence required to support the Order. The Energy Emergency Executive Order refers to a deterioration "in the near future,"[244] while the Grid Reliability Executive Order offers no projection for the timing or location of the increased demand it speculates.[245] This does not satisfy Section 202(c)'s requirements, discussed above in Section V.A., that an emergency must be specific and imminent.

Importantly, the facts contradict the vague assertions of an energy emergency contained in the Executive Orders. For example, America's domestic energy production is at an all-time high given its diverse mix of both fossil and non-fossil fuel resources. The United States is producing record quantities of oil and natural gas,[246] and has been a net energy exporter since 2019.[247]

Similarly, the Energy Emergency Executive Order's assertion that the United States has an "inadequate and intermittent energy supply, and an increasingly unreliable grid" is unsupported by the facts.[248] NERC reports that the bulk power

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[243] *Id.*
[244] Exec. Order 14156, 90 Fed. Reg. at 8,433.
[245] Exec. Order 14262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521 (Apr. 8, 2025).
[246] U.S. Energy Information Admin. ("EIA"), *Short-Term Energy Outlook Data Browser* (Jan. 13, 2026).
[247] EIA, *In-Brief Analysis: The United States was the world's largest liquified natural gas exporter in 2023* (Apr. 1, 2024); EIA, *U.S. Exports of Crude Oil* (Dec. 31, 2025); EIA, *U.S. Energy Facts Explained* (July 15, 2024).
[248] Exec. Order 14156, 90 Fed. Reg. at 8,433.

system is resilient, and that the largest challenge for reliability is extreme weather induced by climate change.[249] Renewable energy resources both mitigate climate change and improve the overall reliability and affordability of the United States' energy supply by tempering the impact of international commodity price swings on natural gas prices and reducing grid operators' reliance on interruptible natural gas deliveries.[250] Solar and wind generated more than 15% of all electricity and 8% of all energy consumed in the United States in 2024.[251]

Next, the Order relies in part on "the expansion of artificial intelligence data centers" referenced in the Grid Reliability Executive Order and other projected demand growth noted in the Department Resource Adequacy Report to support its finding of an emergency.[252] But the Order's discussion of data center load growth is both irrelevant and unsubstantiated.

Neither the Grid Reliability Executive Order nor the Order specify any timeframe for when the increased energy demand from data centers is expected to occur. Section 202(c) does not give the Department the authority to retain generation units for possible conditions that may arise at some indeterminate time in the future. Authority to address long-term threats to resource adequacy rests with the states and FERC and its designated entities, all of which are aware of and extensively planning for this potential load growth. The Order does not cite any evidence that data center

[249] NERC, *2024 State of Reliability* (June 2024), at 5.
[250] FERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 16, 2021), at 172 ("Natural gas fuel supply issues alone caused 27.3[%] of the generating unit outages" during Winter Storm Uri).
[251] EIA, *Short-Term Energy Outlook* (Feb. 11, 2025), *see* the 2024 data; EIA, *December 2025 Monthly Energy Review* (Dec. 23, 2025).
[252] Exhibit A, at 2-3.

load growth will occur in the areas served by Craig Unit 1 during the 90 day period of the Order. As demonstrated in their respective resource plans, the Craig Unit 1 owners are not anticipating any new data centers or other large loads over 50 MW to come online in their service territory in the next 90 days.[253] And where Colorado utilities anticipate data centers coming online in the next five years, they are planning for that additional load through their established resource planning processes.

D. The Order is arbitrary and capricious because it fails to require generation that best meets the claimed emergency.

Even if there were an emergency within the meaning of the FPA, which there is not, Section 202(c)(1) requires the Department to impose requirements that "will best meet the emergency and serve the public interest."[254] The Department has failed to demonstrate that delaying the retirement of Craig Unit 1 satisfies this standard, and the Order is therefore arbitrary and capricious.

i. Preventing Craig Unit 1's retirement does not "meet the emergency," especially where the unit requires costly repairs.

It is unclear how preventing Craig Unit 1's retirement could meet the emergency that the Department alleges. The nature and extent of the claimed emergency are unclear. And even if there were a capacity shortfall in any of the states served by Craig Unit 1 or the WECC-Northwest assessment area, the Order does not provide a reasoned basis for its conclusion that the continued operation of Craig

[253] *See* Section V.C.iii., supra.
[254] 16 U.S.C. § 824a(c)(1).

Unit 1 is the best or even a viable means of alleviating the purported shortfall, particularly in light of the costly repairs required to make Craig Unit 1 available.

The Department cannot demonstrate that Craig Unit 1's retirement meets the emergency because the Order's emergency declaration is unclear and unsupported by the record. The Order does not specify which version of the WECC-Northwest assessment area it is relying upon, which is essential because the assessment areas significantly changed after the 2024 LTRA assessment. This is further confused by the Order's next reference to the WECC-Northwest assessment area being that the "WECC[-]Northwest assessment area, which includes Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming…" despite the fact that in the 2024 LTRA, that assessment area also includes parts of California, Nebraska, Nevada, and South Dakota.[255] Regardless, assuming that the order only refers to the states it called out specifically, Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming, it is Colorado's understanding that Craig Unit 1 is only capable of serving three of those states. The Order also fails to demonstrate that there is a resource shortfall imminent and specific enough to require the continued operation of any particular resource. Thus, it is unclear how Craig Unit 1 could meet the Department's alleged emergency, regardless of how the Order's emergency determination is interpreted.

[255] Exhibit K, at 127.

ii. Delaying the retirement of Craig Unit 1 does not "best" meet the Department's purported emergency.

Even if delaying the retirement of Craig Unit 1 could meet the non-existent alleged emergency in the WECC-Northwest assessment area, the Department has provided no explanation of how that resource would best meet such an emergency. "Best" means "that which is 'most advantageous'" or "excelling all others."[256]

The Order, and the materials upon which it relies, offer no facts that would support a determination that Craig Unit 1 is the "most advantageous" way to address the alleged emergency. Even if the Order had successfully described an emergency scenario for the regions served by Craig Unit 1 or the WECC-Northwest assessment area, the Department has not provided any specific evidence or reasoning explaining why requiring Craig Unit 1 to be available to operate is the most advantageous way to meet the scenario. Other orders issued by the Department in 2025 suffer from the same flaw, as the Congressional Research Service identified in July 2025, noting that Orders issued to the Campbell and Eddystone units have not "identified reliability risks specifically associated with the retirement of the power plants in question at the time they approved those retirements."[257] In this respect, the Department's exercise of its emergency authority in 2025 departs markedly from past uses of Section 202(c) and from the Department's regulations implementing Section 202(c). Those

[256] *Entergy Corp.*, 556 U.S. at 218 (quoting Webster's New International Dictionary 258 (2d ed.1953)); *Best*, Merriam-Webster Dictionary (Jan. 25, 2026).
[257] Exhibit T (Congressional Research Service, Federal Power Act: The Department of Energy's Emergency Authority (June 12, 2025)), at 5-6.

regulations specify that: "[a]ctions under this authority are envisioned as meeting a specific inadequate power supply situation."[258]

"Best's" definition of "excelling all others" requires a comparative judgment that there are no better alternatives. This means the Department must consider alternatives and choose the alternative that is most advantageous to meet the emergency the Department has identified. The Department need not consider every conceivable alternative, but it must consider alternatives within the ambit of the existing policy as well as alternatives which are significant and viable or obvious.[259]

The Department's regulations specify information the Department must consider in deciding how to best address an emergency in a Section 202(c) order. This includes conservation or load reduction actions, efforts to obtain additional power through voluntary means, available imports, demand response, and behind the meter generation resources.[260] The Order considers none of these alternatives. Nor does it explain whether less burdensome measures were considered or exhausted before invoking the Department's emergency authority. Indeed, the Order never quantifies the extent of the emergency it purports to identify within Colorado or any of the states served by Craig Unit 1, making a meaningful alternatives analysis impossible. As discussed in Section V.B.iii, each of the areas served by Craig Unit 1 have significant planning reserve margins. To satisfy Section 202(c)(1)'s requirement that the ordered

[258] 10 C.F.R. § 205.371.
[259] *See Dep't of Homeland Sec.*, 591 U.S. at 30 (failure to consider alternative was arbitrary and capricious); *see also Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 51 (must consider alternatives "within the ambit of the existing [standard]").
[260] 10 C.F.R. § 205.373(g)-(h). While this information is specifically required when a utility applies for a 202(c) order, it illustrates the types of information that is relevant to an alternatives analysis.

solution best meet the emergency, the Order must address why the resources that make up the excess planned reserve margins could not meet the alleged emergency.

This is a particularly glaring omission because the Department addressed their alleged emergency by ordering an inoperable coal unit that required significant repairs to become available to operate,[261] despite the reserve capacity in the region. Craig Unit 1 experienced an outage on December 19, 2025, due to a mechanical valve failure.[262] The Unit was not repaired until January 20, 2025,[263] a third of the way into this 90 day order, and required spending significant resources that would not have been expended absent the Order.[264]

In addition to the significant cost just to make Craig Unit 1 available to operate after the valve failure, Tri-State has stated that retaining Unit 1 "will likely require additional investments in operations, repairs, maintenance and, potentially, fuel supply, all factors increasing costs."[265] The Craig Unit 1 Owners chose to retire Craig Unit 1 for economic reasons.[266] And because the unit was set to retire, Craig Unit 1 has not had major maintenance since 2019;[267] it is also 45 years old, beyond the typical economic design life of a coal burning generator and near the end of a

[261] *See* Exhibit B, ¶ 11.
[262] Tri-State, *U.S. DOE orders Tri-State to keep Craig Generating Station unit operating for next 90 days* (Dec. 31, 2025).
[263] Tri-State, *Tri-State makes Craig Generating Station Unit 1 available to operate in compliance with DOE emergency order* (Jan. 23, 2026).
[264] Tri-State, *U.S. DOE orders Tri-State to keep Craig Generating Station unit operating for next 90 days* (Dec. 31, 2025).
[265] *Id.*
[266] Tri-State, *Craig Station owners, regulators and environmental groups reach agreement on proposed revisions to Colorado regional haze plan* (Sept. 1, 2016).
[267] Exhibit B at ¶ 34.

generator's typical operational life.[268] Keeping Craig Unit 1 running will be more costly now because of the deferred maintenance costs in addition to costs for fuel and continued operations.[269] Colorado's understanding is that Tri-State has, since the issuance of the Order, already begun to expend costs on some of this maintenance.[270] These costs are currently unknown but expected to be significant. It is unclear how Tri-State and the other co-owners will recover these costs, but it is highly likely that they will seek to have ratepayers pay them.[271]

Complicating the fuel issue, Tri-State did not plan on continuing to acquire or use coal for Craig Unit 1 due to its scheduled retirement. Craig Station is supplied with coal from the Colowyo Mine, which ceased coal production at the end of 2025.[272] Tri-State has already contracted with Kiewit Mining Group, Inc., to reclaim the mine following its closure, and reclamation activities were scheduled to begin on or about January 1, 2026.[273] Moreover, the Colowyo mine has been sterilized, meaning it will not be reopened and its operator has transitioned to reclamation activities.[274] It is Colorado's understanding that before the mine's closure, Tri-State obtained enough coal to fuel Craig Units 2 and 3 through their planned retirement dates in 2028 but did not expect to need coal to power Craig Unit 1. If Tri-State needs to use coal acquired

[268] Grid Strategies, *The Economic Cost of a DOE Mandate for the Craig Unit 1 Coal-Burning Generator to Continue Operating* (Dec. 2025), at 2.
[269] Exhibit D ¶¶ 14-15.
[270] *See* Exhibit B, ¶ 34.
[271] Exhibit D ¶ 18.
[272] Jaffe, M., *Tri-State expects federal order to keep coal-fired power plant in northwestern Colorado running* (Nov. 14, 2025).
[273] Tri-State, *Colowyo Mine to conclude coal production in 2025, transitioning to full reclamation* (Aug. 7, 2025).
[274] Weiser, C., *Colowyo coal mine near Craig lays off 133 workers as mine closes* (Nov. 26, 2025); WarnTracker.com, *1 WARN Layoff Notice for ColoWho Coal Company LP on Nov 2025* (2025).

to fuel Craig Units 2 and 3 to unexpectedly fuel Craig Unit 1, it will likely not have enough supply to also fuel the other units. Tri-State would then have to buy more expensive, and possibly dirtier, coal from another source.[275]

In addition, coal generation is generally more costly than other generation resources.[276] The inefficiency of running a coal plant makes it uneconomic in general and is the main reason that Craig Unit 1 (and eventually, the rest of Craig Station) was slated for retirement. In fact, the CoPUC approved coal fired generating unit retirements to be replaced with lower cost wind, solar, and use of gas as a capacity resource because wind and solar were the lowest cost resources available and it was cheaper to add new renewables, storage and gas generation to the system and retire coal units.[277]

Coal generation also does not guarantee reliability, which further emphasizes that Craig Unit 1 would not best meet any emergency. A 2021 report by the CoPUC found that Comanche Unit 3, Colorado's newest coal plant, which supplies portions of Public Service's territory, averaged 91.3 days per year of outages and was out of

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[275] *See* Exhibit B, ¶ 32.

[276] Weiser, C., *Colowyo coal mine near Craig lays off 133 workers as mine closes* (Nov. 26, 2025). A report by Grid Strategies found that ratepayer costs could exceed $3 billion per year if the Department mandates that all of the fossil power plants scheduled to retire between the time the report was published in August 2025 and the end of 2028 remain open. Grid Strategies asserts that the Department is ignoring the careful planning of states and utilities and "overriding cost-minimizing retirement decisions that have been made by state utility regulators and merchant power plant owners based on extensive information regarding the cost, performance, condition, and need for each plant." *see also* Grid Strategies, LLC, *The Cost of Federal Mandates to Retain Fossil-Burning Power Plants* (Aug. 2025) at 3; Exhibit O, which cost a staggering $29 million over the first 38 days; Solomon, M., et al., *Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment* (Jan. 2023), at 1-2 (a report by Energy Innovation found that "99[%] of all coal-fired plants in the U.S. are more expensive to operate on a forward looking basis than the all-in cost of renewable energy projects," and that "all but one of the country's 210 coal plants are more expensive to operate than either new wind or solar.").

[277] CoPUC, Decision No. C18-0761, issued on September 10, 2018, in Proceeding No. 16A-0396E, ¶ 103.

service for nearly all of 2020.[278] In fact, when Public Service experienced a supply constraint in Summer of 2025, 80% of its unavailable power was caused by coal unit outages.[279]

This is not just true in Colorado, but also in other states, yet the Department has ignored this reality in issuing Section 202(c) orders. For example, the R.M. Schahfer Generating Station has been in a forced outage since July, after experiencing another forced outage from February 16, 2025 to June 23, 2025.[280] Yet, despite the unit being offline, the Department issued an order requiring it to remain available on December 23, 2025.[281] Finally, the newest large coal-fired plant in the U.S. suffered an outage in fall of 2025 and will now be offline until March 2027.[282] This is the second time that plant has been unable to operate for a year or more.

These facts illustrate a clear pattern: coal is not the first choice when considering reliable, affordable generation. And the Order contains no facts (either in its text or in the cited materials) that supports any determination that ordering continued availability and operation of an off-line coal unit is a reasonable response to a perceived emergency, much less "best meets" such an emergency. Given the cost of Craig Unit 1 and questions of reliability surrounding coal plants generally, the

[278] Kohler, J., *Comanche 3, Xcel Energy's troubled coal plant, likely out of commission for months* (Oct. 24, 2025); CoPUC, *Staff Report Volume 1,* Public, filed on March 1, 2021, in Proceeding 20I-0437E, at 65.
[279] Kohler, J., *Comanche 3, Xcel Energy's troubled coal plant, likely out of commission for months* (Oct. 24, 2025).
[280] *Id.*
[281] Exhibit S.
[282] Institute for Energy Economics and Financial Analysis, *Newest big U.S. coal-plant offline until 2027* (Oct. 7, 2025); Tri-State, *Tri-State makes Craig Generating Station Unit 1 available to operate in compliance with DOE emergency order* (Jan. 23, 2026).

Department has failed to demonstrate that Craig Unit 1's continued operation "best meets the emergency" and therefore the Order is arbitrary and capricious

E. The Order's terms fail to comply with Section 202(c)'s requirements.

i. The Order is contrary to law because it attempts to regulate a generation facility by requiring the Craig Unit 1 Owners to undertake substantial and expensive repairs that they otherwise would not conduct.

Given that Craig Unit 1 was offline at the time the Order was issued, compliance with the Order required the repair of Craig Unit 1.[283] This requirement is outside the scope of the Department's Section 202(c) authority, even if there was adequate proof of an energy emergency.

The Department's emergency power under Section 202(c) is bounded both by the provision's specific language and Congress's clear, repeated direction in the FPA to respect the states' authority over generating facilities. When an actual emergency exists, Section 202(c)(1) authorizes the Department to require just two specific things: (1) "temporary connection of facilities" and (2) "generation, delivery, interchange, or transmission of electric energy."[284] The only reference to "facilities" in the authorizing provision of Section 202(c)(1) appears in the clause relating to temporary connections, not in the clause pertaining to "generation" of electric energy. And that clause authorizes only "connections" of facilities: it does not provide authority to regulate the individual facilities. The difference in Congress's

[283] Exhibit B, ¶ 11; Tri-State, *Tri-State makes Craig Generating Station Unit 1 available to operate in compliance with DOE emergency order* (Jan. 23, 2026).
[284] 16 U.S.C. § 824a(c)(1).

word choice in these clauses – referencing "facilities" in one authorizing provision but not the other – must be given effect.[285]

As discussed above in Section V.C.i., Section 201(b)(1) of the FPA specifically states that unless otherwise provided, there is no federal jurisdiction over "facilities used for the generation of electric energy." Courts have also held that Section 201(b)(1) reserves authority over electric generating authority to the states, reiterating that states retain the right "to require the retirement of existing generators."[286] Given Congress's use of the term "generating facilities" elsewhere in the statute, if it had intended to give the Department authority in Section 202(c)(1) over generating facilities that otherwise resides with the states, it would have had to do so explicitly.[287] Instead, the provision conspicuously excludes authority to manage the physical characteristics of power plants.

Thus, Congress purposely limited and particularized the Department's emergency powers, carefully avoiding intrusion on the states' authority over generating facilities recognized in Section 201(b)(1). As stated in the legislative history, the emergency powers in Section 202(c)(1) "which were indefinite in the original bill have been spelled out with particularity."[288] The Department may neither directly regulate generation facilities nor impose requirements aimed at the facilities,

[285] *See e.g. Gallardo v. Marstiller*, 596 U.S. 420, 430 (2022); *see also Gomez-Perez v. Potter*, 553 U.S. 474, 486 (2008).
[286] *Conn. Dep't of Pub. Util.*, 569 F.3d at 481; *see also, e.g., Hughes*, 578 U.S. at 155.
[287] *Gregory,* 501 U.S. at 460 (The clear statement rule requires Congress to make its intent unmistakably clear if it intends a statute to alter the usual constitutional balance between the federal government and the states.); *see also DeMarco*, 4 F.3d at 169 (Congress must express an affirmative intention to use a statute to alter the federal balance.)
[288] *See* S. Rep. No. 74-621, at 19 (1935).

even if nominally regulating within its sphere.[289] This means that the Department may not require generation that necessitates the utility taking steps reserved to state authority, such as building a new generating unit or refurbishing a broken one. Therefore, the Order is outside the bounds of its Section 202(c) authority even if there is an emergency, because it managed the physical characteristics of Craig Unit 1 by requiring its repair.

ii. The Order violates Section 202(c)(2) because it fails to ensure consistency with federal and state environmental laws and fails to minimize adverse environmental impacts.

Section 202(c)(2) imposes mandatory duties on the Department if a 202(c) order "may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation[.]"[290] The Order explicitly conflicts with the environmental laws and regulations that apply to the Craig Station Unit 1 Owners, and may also result in additional conflicts with environmental laws and regulations that apply to the State of Colorado.[291] The Department failed to comply with these requirements, rendering the Order illegal.

a. <u>The Order directly conflicts with federal and state laws requiring Craig Unit 1 to close by December 31, 2025.</u>

The Order directly conflicts with federal and state environmental laws and regulations that require the closure of Craig Unit 1 by December 31, 2025. These include Colorado Air Quality Control Commission ("AQCC") Regulation Number 23,

[289] *See F.E.R.C. v. Elec. Power Supply Ass'n*, 577 U.S. 260, 281-82 (2016); *see also Hughes*, 578 U.S. at 164-65.
[290] 16 U.S.C. § 824a(c)(2) (emphasis added).
[291] *See* Exhibit B.

Colorado's Regional Haze SIP adopted pursuant to the Federal Clean Air Act, and Tri-State's operating permit issued pursuant to Title V of the Federal Clean Air Act.[292]

The AQCC (with the Craig Station owners' consent) adopted the December 31, 2025 closure date into state law through Regulation Number 23, which regulates regional haze.[293] The EPA then approved this closure date into federal law when it approved Colorado's Regional Haze SIP in 2018.[294] In addition, Craig Unit 1 is a major source of air pollution[295] and therefore requires, and operates under, an operating permit issued pursuant to Title V of the Federal Clean Air Act.[296] A Title V permit includes emissions limits, operational requirements, reporting obligations, and other requirements to ensure the safe and environmentally responsible operation of major sources. Condition 1.10 of Craig Unit 1's operating permit specifies that the Unit must close on or before December 31, 2025.[297]

In addition, the Colorado Legislature directed the AQCC to adopt rules to help meet statewide statutory GHG reduction goals.[298] The Order's direction for continued availability and operation of Craig Unit 1 may restrict Colorado's ability to meet these statutory goals.

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[292] *Id.*
[293] *See* 5 Colo. Code Reg. § 1001-27:A.IV.D.
[294] Air Plan Disapproval; Colorado; Regional Haze Plan for the Second Implementation Period, 91 Fed. Reg. 3,048, 3,049, fn. 9 (Jan. 26, 2026); EPA, *EPA Approved Statues and Regulations in the Colorado SIP* (Jan. 6, 2026); 83 Fed. Reg. 31,332 (July 5, 2018).
[295] Craig Station is a major source and Craig Unit 1, by volume of pollution emitted, is itself a major source. Exhibit B at 27; Exhibit KK (Division, *Operating Permit No. 96OPMF155* (July 1, 2021));
[296] *See* Exhibit KK; 42 U.S.C. § 7661a(a).
[297] *See* Exhibit KK, at 25.
[298] *See* § 25-7-105(1)(e), Colo. Rev. Stat.; Exhibit B, ¶ 29; § 25-7-102(2)(g), Colo. Rev. Stat.

Thus, by ordering the Craig Station owners to return Craig Unit 1 to service and to be available to operate beyond the December 31, 2025 closure date, the Order directs the owners to violate both state and federal law and is subject to the requirements of Section 202(c)(2).

b. The Order does not comply with Section 202(c)(2).

Because the Order conflicts with state and federal environmental laws, the Department was required to ensure that the Order: 1) " requires generation, delivery, interchange, or transmission of electric energy *only* during hours necessary to meet the emergency and serve the public interest," 2) "to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation," and 3) "minimizes any adverse environmental impacts."[299] The Department's Order contains no conditions or instructions that meet these requirements.

First, by referring to the "hours" necessary to meet the emergency, Congress placed a high burden on the Department to demonstrate that the remedy provided in a Section 202(c) order is narrowly tailored to the specifics of the emergency that the order is designed to address. Even if the Department had identified a true emergency (which it has not), the FPA authorizes the Department to compel generation only when an emergency shortage of electric energy would occur absent operation of Craig Unit 1 specifically.[300] The Order's terms fail to require operation "only during the

[299] 16 U.S.C § 824a(c)(2) (emphasis added).
[300] *Id.*; *see, e.g.*, Department, Order No. 202-17-4, *Summary of Findings* (Sept. 14, 2017), at 9 ("authorizing operation of" units subject to emergency order "only when called upon . . . for reliability purposes," according to "dispatch methodology" approved by Department).

hours necessary to meet the emergency" described by the Order and violates Section 202(c)(2) because the Order does not establish any limited hours or other parameters for Craig Unit 1 to follow.

The Order also contains no limitation on how SPP West and WACM may call on Craig Unit 1. By leaving the dispatch of Craig Unit 1 entirely in the hands of these entities, the Department is failing to properly limit operation as required by Section 202(c). Without a clearly defined emergency, WACM and SPP West have no standards to determine under what circumstances they should "require the continued operation of Craig Unit 1." The premise for such continued operation is the energy "emergency" articulated in the Order, but it is impossible to know what conditions require Craig Unit 1 to operate by reading the Order.[301] Orders issued by the Department prior to 2025 demonstrate that the Department is capable of including appropriate limiting conditions in Section 202(c) orders. For example, in 2022, the Department issued an order in response to periods of extreme heat, drought conditions, and threat of wildfires that were expected to occur over several days and threaten the reliable operation of the bulk electric power system in California. That order directed the Balancing Authority of Northern California to dispatch specific units only "under the following conditions: the issuance and continuance of an Energy Emergency Alert Level[ ] 2 condition or greater between the hours of 14:00 Pacific Time and 22:00

[301] Indeed, the Order contains confusing and contradictory instructions regarding the unit's operations, stating both that "Craig Unit 1 shall not be considered a capacity resource" and that its "continuous operation" is required. Exhibit A, at 1, ¶ G. Presumably, this means that the unit may only be called up by WAPA or SPP when there is an actual supply shortage that existing resources cannot meet. But if that is the intent, it is not clear from the face of the Order.

Pacific Time after exhausting all reasonably and practically available resources."[302] Although Section 202(c)(2) requires the Department to include limiting conditions in the Craig Unit 1 Order as well, it chose not to, and that choice is contrary to law.

Second, Section 202(c)(2) requires that where an order may result in a conflict with environmental law or regulation, it must "to the maximum extent practicable, [be] consistent with any applicable Federal, State or local environmental laws." The Order contains no analysis of the plant's environmental obligations and no operational criteria established to minimize impacts. The Order merely states that "operations of Craig Unit 1 must comply with applicable environmental requirements to the . . . . extent feasible while operating consistently with emergency conditions."[303]

There are numerous environmental requirements that are affected by the continued operation of the Craig Unit 1 facility, but the Department failed to identify mechanisms to allow Craig Unit 1 to remain available while minimizing conflicts with these requirements. The Department also did not consult with the State of Colorado, including its environmental regulators, who could have advised on ways to minimize impacts.[304] The Order does not reference or discuss the applicable environmental laws

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[302] Department, Order No. 202-22-2 (Sept. 4, 2002) at 4; *see also Letter from Kevin Kolevar, Director, Office of Electricity Delivery and Energy Reliability to Robert Driscoll, CEO, Mirant Mid-Atlantic, LLC* (May 31, 2007) (Letter from DOE describing the emissions limitations that a utility should follow when complying with a 202(c) order.); Department, Order No. 202-17-1 (Apr. 14, 2017) (202(c) Order from DOE instructing SPP to adopt a temporary operating guide and comply with additional operating requirements set out in an EPA compliance order).

[303] Exhibit A, ¶ C.

[304] Exhibit B, ¶¶ 10, 32-34; *see also* Section 103 of the Department of Energy Organization Act, 42 U.S.C. § 7113 (requiring the Department to give due consideration to the needs of states when proposing any action that conflicts with a state energy plan, and to attempt to resolve conflicts through consultations with appropriate state officials). The Order plainly conflicts with Tri-State's decision-making process, the CoPUC's approved ERPs, the EPA-approved Regional Haze SIP, and AQCC regulation.

and regulations impacted by the Order, revealing the Department's failure to analyze these requirements to ensure compliance with environmental standards.

In particular, the Order fails to reflect any consideration of interactions with the Federal Clean Air Act Regional Haze program[305] or National Ambient Air Quality Standards ("NAAQS") attainment and permitting programs. The Regional Haze program requires states to reduce emissions of NOx, SO_2, and PM from sources that affect Class I federally protected areas.[306] States must conduct detailed and expensive analyses, and based on the results of those analyses, impose federally enforceable controls and emission limits upon the largest and most impactful sources of haze pollutants.[307] The Federal Clean Air Act, through the NAAQS attainment and permitting programs, also directs states to achieve and maintain air quality standards for certain pollutants, including NOx, SO_2, and PM.[308] The Department does not appear to have conducted any analysis of the impact keeping Craig Unit 1 operational may have on sources' and Colorado's ability to comply with either of these programs. The Order gives no guidance as to whether it creates conflicts with either of these requirements and, if it does, on how to navigate them.

[305] EPA recently disapproved Colorado's Regional Haze Plan for Round 2 (which does not involve Craig Unit 1) by, in part, pointing to this Order. 91 Fed. Reg. at 3,049, fn. 9 (Jan. 26, 2026). While Colorado maintains that EPA's action was improper, and that its Regional Haze SIP currently meets federal requirements, it does reveal that EPA considers Craig Unit 1 relevant to Colorado's compliance with Regional Haze requirements now and in the future. The federal government must, but fails to, take a consistent position in the Regional Haze SIP disapproval and the Order as it relates to Craig Unit 1.
[306] *See* 42 U.S.C. §§ 7491, 7492; *see also* implementing regulations at 40 C.F.R. § 51.300-309.
[307] *Id*.
[308] *See, e.g.,* 42 U.S.C. §§ 7409, 7410.

Accordingly, the Order violates the Department's statutory obligation to "ensure" the maximum feasible compliance with applicable environmental standards.[309] This obligation requires the Department to offer some discrete guidance as to the unit's operations, rather than merely parroting the statutory text. This lack of detail also makes it impossible for Colorado's environmental regulators to know what operational activities are excused from environmental compliance by the Order, increasing the complexity and burdens associated with any state enforcement actions.

Third, Section 202(c)(2) requires the Department to minimize the adverse environmental impacts of the Order, which the Order fails to do. This mandate is textually and substantively distinct from the Department's (also unfulfilled) obligation to ensure maximum practicable compliance with environmental standards. By failing to include a sufficient or legal description of the purported emergency, this Order authorizes Unit 1 to generate electricity and pollute beyond any emergency needs, thereby increasing the environmental impacts that by law the Order must minimize. When Craig Unit 1 operates, it emits NOx, SO_2, fine PM, GHG emissions, HAPs, and other harmful pollutants.[310] The Order includes no measures to mitigate impacts when compliance with environmental standards proves impracticable, even though those types of measures have been routinely included in past orders.[311] At a minimum, the

[309] 16 U.S.C. § 824a(c)(2) (emphasis added).
[310] Exhibit B, ¶ 13.
[311] *See, e.g.*, Department, Order No. 202-17-4 (Sept. 14, 2017) at 2 (permitting non-compliant operation only during specified hours, and requiring exhaustion of "all reasonably and practicably available resources," including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions); Department, Order No. 202-22-4 (Dec. 12, 2022) (requiring "reasonable measures to inform affected communities" of non-compliant operations).

statute requires the Department to include sufficiently detailed reporting obligations to ascertain what impacts result from emergency operations; without such reporting, the Department has no ability to "ensure" that adverse impacts are minimized.[312] The Order here instead merely requires "such additional information" as the Department, in the future, may (or may not) "request[] . . . from time to time." That possibility of future, unspecified information gathering cannot satisfy the statute's demand that the Department "ensure" that its Order minimizes environmental impacts.[313]

Similarly, the Order does not address or assess mechanisms to minimize the pollution from Craig Unit 1 that would or could be associated with its operation in response to the Order. It also does not address or assess the environmental impacts associated with the acquisition and transport of additional coal that may be necessary to facilitate Unit 1's operation, and contains no limitations on the type of coal that may be used so as to minimize the impacts of any new emissions. Not all coal is inherently compatible with the units at the Craig Station, and depending on where new coal is sourced from, there could be significant emissions and costs associated with the distances required to import that coal.[314] Nor are these impacts addressed by the Department's cursory instruction to Tri-State to comply with applicable environmental requirements "to the maximum extent feasible." Because the Department made no attempt to address the requirements of Section 202(c)(2), the Order is unlawful.

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[312] *See, e.g.,* Department, Order No. 202-24-1 (Oct. 13, 2024) at 4-5 (requiring detailed data on emissions of pollutants).
[313] 16 U.S.C. § 824a(c)(2).
[314] Exhibit B, ¶¶ 32-33.

For these reasons, the Order fails to comply with the Department's obligations under Section 202(c)(2), and should be withdrawn.

F. The Order is designed to support the federal administration's policy goal of propping up the coal industry, making it an arbitrary and capricious pretext.

Agency action is arbitrary and capricious when it rests on a "pretextual" reason that is "incongruent with what the record reveals about the agency's priorities and decision-making process."[315] Agency decisions that feature "unjustifiable bias or partisanship are precisely the types of agency actions that 'would work a violation of the arbitrary-and-capricious standard.'"[316] Here, the record demonstrates that there is no evidence of an energy emergency within the meaning of Section 202(c) that would support issuance of the Order. Instead, the Order is a transparent attempt to favor the Trump administration's preferred energy source and revive the coal industry. Because the Order is pretextual and divorced from any actual emergency, the Order violates the law and must be withdrawn.

i. The Department's 2025 Section 202(c) orders demonstrate a pattern of arbitrary and capricious behavior designed to carry out a policy goal.

Over the course of 2025, the Department and the President have made clear that they are using Section 202(c) orders to prevent coal-fired generating plants from retiring, simply because the current administration prefers coal and other fossil fuel generation. On his first day in office, the President declared a "National Energy Emergency" and identified coal as one of his preferred energy resources.[317] The President later directed the Department to "streamline" its use of emergency orders,

[315] *Dep't of Commerce*, 588 U.S. at 785.
[316] *Level the Playing Field*, 961 F.3d at 464 (quoting *Hagelin v. FEC*, 411 F.3d 237, 242 (D.C. Cir. 2005)).
[317] Exec. Order 14156, 90 Fed. Reg. 8,433, 8,434 (Jan. 20, 2025), Sec. 8(a).

explaining that his goal was to "revitaliz[e] America's big beautiful coal industry to support grid stability and American jobs."[318]

Following these pronouncements, the Department has issued orders for nearly every coal plant scheduled to retire in 2025, all for the statutory maximum of 90 days. None of these orders meet the same criteria as previous orders issued pursuant to Section 202(c). Specifically, none were publicly requested by a utility;[319] none were based on an inability to comply with environmental laws; and none were responsive to or tailored to meet a specific, imminent, unexpected and temporary emergency. The Department Secretary Wright has confirmed that "[t]he goal [of the recent 202(c) orders] is to stop the political closure of coal plants."[320]

For example, the Department's recent order to keep R.M. Schahfer Plant Units 17 and 18 running ignores the fact that Unit 18 was in a forced outage from February 16, 2025 to June 23, 2025, and then again from July 9, 2025 until now. It is unclear how a plant that barely operated throughout 2025 and was not operational at the time the Department issued its Section 202(c) order could help in an alleged emergency. The Schahfer Plant Order also fails to describe an emergency, and in fact actually recognizes that there is anticipated to be a surplus of generation capacity in

[318] The White House, *Fact Sheet: President Donald J. Trump Strengthens the Reliability and Security of the United States Electric Grid* (Apr. 8, 2025); *see also* New York Times, Trump Signs Orders Aimed at Reviving a Struggling Coal Industry, April 8, 2025); Exec. Order 14261, Reinvigorating American's Beautiful Clean Coal Industry and Amending Executive Order 14241, 90 Fed. Reg. 15,517 (April 14, 2025); Exec. Order 14260, Protecting American Energy from State Overreach, 90 Fed. Reg. 15,513 (April 14, 2025); Regulatory Relief for Certain Stationary Sources To Promote American Energy, 90 Fed. Reg. 16,777 (April 21, 2025).

[319] It is common practice for the Department to post the request of the entity requesting a specific order within that order's docket. *See, e.g.* Department, *2024 DOE 202(c) Orders*; Department, *2023 DOE 202(c) Orders*.

[320] Department, *Energy Department Convenes First National Coal Council Meeting Under Renewed Charter, Reaffirming Coal's Role in Unleashing American Energy* (Jan. 15, 2026).

MISO's 2025-2026 winter season,[321] revealing that order, like the Order, to be incongruent with the record facts.[322]

Together, these orders demonstrate that, rather than addressing emergencies, the Department is working to prevent the retirement of coal plants across the United States.

ii. Despite claims it is addressing energy emergencies, the Department is simultaneously interfering with efforts to increase generation through renewable resources.

At the same time the Department is claiming that an energy emergency justifies exercise of its Section 202(c) emergency authority, it is also working to stymie development of renewable generation sources, particularly wind and solar.

The Department's own website explains that "wind energy offers many advantages which explains why it's one of the fastest-growing energy sources in the world[,]"[323] and that solar energy "can support household savings, energy independence, economic opportunities, grid reliability, resilience, security and affordability, and a safer planet."[324] Wind and solar energy are also extremely cost competitive with other energy sources. The most recent Levelized Cost of Energy+ Report ("LCOE Report") found that "[o]n an unsubsidized $/MWh basis, renewable energy remains the most cost-competitive form of generation."[325] Renewables are also important in a high demand scenario, as they are the "quickest-to-deploy

[321] Exhibit S, at 3.
[322] *See Dep't of Commerce v. New York*, 588 U.S. at 785.
[323] Department, *Advantages and Challenges of Wind Energy*.
[324] Department, *Solar Energy*.
[325] Lazard LCOE, *Levelized Cost of Energy+* (June 2025), at 4.

generation resources."[326] Colorado has confirmed that wind and solar energy are low cost options to provide reliable electricity generation in the Northwest Colorado region, including Craig.[327]

Despite these advantages, the federal government and the Department have been actively repressing wind, solar, and hydrogen fuel deployment. Alongside the Energy Emergency Executive Order, President Trump issued an executive memorandum ("Memo") directing federal agencies to pause the issuance of all wind energy authorizations.[328] That Memo has since been declared unlawful and vacated.[329] In addition, the One Big Beautiful Bill Act ended subsidies for wind and solar energy projects years earlier than planned.[330] The Department has also cut funding for grants that were supposed to go to projects such as hydrogen technology and upgrades to the electric grid.[331] And although the solar industry installed nearly 18 GW of new

[326] *Id.*
[327] *See* Colorado Energy Office, *Exploring Advanced Energy Solutions for Rural Colorado* (Dec. 19, 2025) (study looked at both the levelized cost of energy and the levelized cost of capacity for multiple generation options and found that solar combined with battery storage has the lowest levelized cost of electricity, and wind combined with battery storage has the lowest cost levelized net cost of capacity).
[328] Temporary Withdrawal of All Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects, 90 Fed. Reg. 8,363 (Jan. 29, 2025).
[329] Judgement Ordered 12/18/2025 in *State of New York v. Trump*, 25-cv-11221-PBS (D. Mass.).
[330] Sidley, *The "One Big Beautiful Bill" Act – Navigating the New Energy Landscape* (Jul. 15, 2025); *see also* 26 U.S.C.A. § 45Y (creating wind production tax credits, passed Aug. 2022); 26 U.S.C.A. § 48E (creating solar investment tax credits, passed Aug. 2022); One Big Beautiful Bill Act, Pub. L. 119-21, Title VII, § 70512-3, 139 Stat 72 (July 4, 2025) (amending 26 U.S.C.A § 45Y and 26 U.S.C.A. § 48E to end subsidies for wind and solar projects).
[331] *See* Walton, R., *DOE cancels $7.6B in clean energy awards in states that voted against Trump* (Oct. 2, 2025); Banse, T., *Trump administration yanks funding for Northwest green hydrogen project* (Oct. 2, 2025); Kaufman, A., *Trump's cuts to billion-dollar hydrogen hubs rattle industry* (Oct. 2025).

capacity in the first half of 2025, the federal administration's efforts to stymy wind and solar energy has resulted in significantly reduced solar deployment.[332]

As the Department has observed, "the reliability of the power grid is intrinsically a system-wide property that cannot be ensured by an individual resource or technology in that system."[333] Focusing on one technology instead of a portfolio of resource adequacy measures increases risk.[334] The Department's current single-minded focus on coal reflects a policy preference as opposed to a desire to address any actual energy emergency, and constitutes an unlawful pretext.

G. The Department failed to comply with NEPA.

By requiring Craig Unit 1 to remain available beyond its planned retirement date, the Order has the potential to cause significant environmental impacts and requires evaluation under NEPA.[335] Because the Department has misused its emergency authority in the Order,[336] it cannot rely on the exception to NEPA's implementing procedures that applies to emergency actions. Quite simply, there is no "emergency situation[] that demand[s] immediate action" here.[337] As demonstrated above, there is no current or imminent energy shortfall or near-term reliability emergency that justifies continued operation of Craig Unit 1.[338] Accordingly, to the

[332] Wood Mackenzie, *Solar and storage dominate new power additions in first six months of Trump administration as federal policies drive up energy costs* (Sept. 9, 2025); Economy+Environment, *Clean Economy Works: November 2025 Anaysis* (Dec. 12, 2025).
[333] Department, *The Future of Resource Adequacy* (Apr. 2024) at 8.
[334] *Id.*
[335] 42 USC 4336(b), *supra*.
[336] *See* Sections V.A-F, *supra*.
[337] 10 C.F.R. § 1021.103.
[338] *See* Section V.C., *supra*.

extent the Department is relying on the exception for emergency actions to avoid full NEPA analysis, such reliance is contrary to law.

Moreover, the Department's NEPA implementing regulations recognize that where an action has the potential to cause significant impacts on an environmentally sensitive area, such as federally- and state-designated wilderness areas, national parks, scenic areas, and similar resources, the action is not appropriate for categorical exclusion and instead must be analyzed under NEPA.[339] Here, retirement of Craig Unit 1 by December 31, 2025 is a requirement of Colorado's federally approved SIP to address the Federal Clean Air Act visibility program. This program is designed to protect federally-designated areas home to sensitive ecosystems or species potentially harmed by even small increases in pollution.[340] Specifically, the Colorado Regional Haze SIP, which incorporated Craig Unit 1's retirement date in Round 1, is designed to protect national parks and wilderness areas in Colorado including Black Canyon of the Gunnison National Park, Great Sand Dunes National Park, Rocky Mountain National Park, and Mount Zirkel Wilderness Area.[341] Craig Unit 1 is located near the Mount Zirkel Wilderness Area.[342] As a result, the Department's own NEPA regulations dictate that the action was subject to NEPA review.

[339] 10 C.F.R. Part 1021, Appx. B, § B(4)(iv).
[340] Exhibit B, ¶ 26.
[341] Exhibit MM (Division, *Colorado Visibility and Regional Haze SIP for the Twelve Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016)).
[342] 5 Colo. Code Regs. § 1001-5:F.VI. (2014).

VI. Request For Stay

In addition to seeking rehearing, the State of Colorado moves the Department for a stay of the Order until the conclusion of judicial review.[343] The Department should also refrain from renewing the Order as currently drafted beyond its current expiration in March 2026. The Department has the authority to issue a stay under the Administrative Procedure Act and should do so where "justice so requires."[344] In deciding whether to grant a request for stay, agencies consider: (1) whether the party requesting the stay will suffer irreparable injury without a stay; (2) whether issuing a stay may substantially harm other parties; and (3) whether a stay is in the public interest.[345]

Injuries under this standard must be actual, certain, imminent, and beyond remediation.[346] Financial injury is irreparable where no "adequate compensatory or other corrective relief will be available at a later date, in the ordinary course of litigation."[347] Environmental injury, however, "can seldom be adequately remedied by money damages and is often permanent or at least of long duration, *i.e.*,

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[343] 18 C.F.R. § 385.212.
[344] 5 U.S.C. § 705.
[345] *See Nken v. Holder*, 556 U.S. 418, 434, 436 (2009); *Ohio v. EPA*, 603 U.S. 279, 291 (2024); *see, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,020, at P 41 (2023); *ISO New Eng. Inc.*, 178 FERC ¶ 61,063, at P 13 (2022), *rev'd on other grounds sub nom. In re NTE Conn., LLC*, 26 F.4th 980, 987-88 (D.C. Cir. 2022).
[346] *Mexichem Specialty Resins, Inc. v. EPA*, 787 F.3d 544, 555 (D.C. Cir. 2015); *Wis. Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985); *ANR Pipeline Co.*, 91 FERC ¶ 61,252, at p. 61,887 (2000); *City of Tacoma*, 89 FERC ¶ 61,273, at p. 61,795 (1999) (recognizing that, absent a stay, options for "meaningful judicial review would be effectively foreclosed").
[347] *Wis. Gas Co.*, 758 F.2d at 674 (quoting *Va. Petroleum Jobbers Ass'n v. Fed. Power Comm'n*, 259 F.2d 921, 925 (D.C. Cir. 1958)); *see also In re NTE Conn., LLC*, 26 F.4th at 990-91. (Colorado refuses to concede that its residents, as ratepayers, should bear this cost of the Department's illegal actions here. Nonetheless, we assume that neither the Department nor the Craig Station owners want to bear those costs either, and will seek to impose them on Coloradans.)

irreparable. If such injury is sufficiently likely, therefore, the balance of harms will usually favor the issuance of an injunction to protect the environment."[348]

A. Colorado and its people will suffer irreparable injury absent a stay.

Here, a stay is necessary to prevent irreparable harm to the State of Colorado. If Craig Unit 1 is required to operate, it will result in emissions of dangerous air pollutants that would not otherwise have occurred but for the Order. And even requiring Craig 1 to be available to operate, as the Order directs, will increase costs that may be passed on to ratepayers, along with increasing pollution directly through readying activities, and indirectly through the sourcing and transportation of fuel. Even if the unit dispatches rarely or not at all, these excess pollutants contribute to and exacerbate respiratory problems, cardiovascular issues, and other health conditions.[349]

A stay would not result in harm to any other interested parties. The issuance of a stay would not harm end-use electricity consumers because there is no emergency addressed by the operation of Craig Unit 1. The lack of an actual emergency means that a stay would not disrupt the provision of electricity. Furthermore, because Tri-State had already planned for the closure of Craig Unit 1, a stay would have the effect only of relieving Tri-State of the administrative, compliance, and planning burdens imposed by the Order. On the balancing of equities, there is therefore no meaningful countervailing harm that would follow from a stay.

[348] *Amoco Prod. Co. v. Vill. of Gambell*, 480 U.S. 531, 545 (1987).
[349] Exhibit B, ¶ 21.

B. A stay is in the public interest.

There is no public interest served by the Order, and a stay will only benefit the public. First, the Order exceeds the Department's authority; it has provided no reasonable grounds to substantiate any near-term or imminent shortfall in electricity supply that would necessitate Craig Unit 1's continued operation.[350] Second, a stay would protect the broader public from the costs and additional pollution produced by unnecessary operation of Craig Unit 1.

VII. Conclusion

For the reasons set forth above, the State of Colorado respectfully requests that the Department grant intervention; grant a rehearing and rescind the Order; and stay the Order.

Filed on January 28, 2026.

Submitted by:
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Attorney General

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Assistant Attorney General

[350] *See League of Women Voters v. Newby*, 838 F.3d 1, 12 (D.C. Cir. 2016) (noting that "there is a substantial public interest 'in having governmental agencies abide by the federal laws that govern their existence and operations'") (quoting *Washington v. Reno*, 35 F.3d 1093, 1103 (6th Cir. 1994)).

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Certificate of Service

This is to certify that I have duly served the foregoing, **The State Of Colorado's Request For Rehearing, Motion to Intervene, and Stay Request**, upon all parties below electronically via e-mail this 28th day of January, 2026:

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State of Colorado's Exhibit List

Exhibit No.	Document Description
A	Department, Order No. 202-25-14 (Dec. 30, 2025)
B	Declaration of Josh Korth Declaration (Jan. 26, 2025)
C	Declaration of Erin O'Neil (Jan. 26, 2025)
D	Declaration of Joseph Pereira (Jan. 23, 2025)
E	CoPUC, Decision No. C25-0612, issued on August 26, 2025, in Proceeding No. 23A-0585E.
F	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-2 (Tri-State, *2020 IRP/ERP,* Public (Dec. 1, 2020)
G	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-1 (Tri-State, *Responsible Energy Plan* (Jan. 2020)
H	Salt River Project, *2023 Integrated Systems Plan*
I	Department, Order No. 202-25-7 (Aug. 20, 2025)
J	CoPUC, 120 Day ERP Implementation Report, Public, filed on April 11, 2025, in Proceeding No. 23A-0585E
K	NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024)
L	NERC, *2025-2026 Winter Reliability Assessment* (Nov. 2025)
M	Department, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (July 2025)
N	Motion to Intervene and Protective Request for Rehearing by the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York, filed on August 6, 2025 with the Department
O	Department, Order No. 202-25-3 (May 23, 2025)
P	Department, Order 202-25-4 (May 30, 2025)
Q	Department, Order No. 202-25-11 (Dec. 16, 2025)
R	Department, Order No. 202-25-13 (Dec. 23, 2025)
S	Department, Order No. 202-25-12 (Dec. 23, 2025)
T	Congressional Research Service, *Federal Power Act: The Department of Energy's Emergency Authority* (June 12, 2025)
U	Department, Order 202-25-9 (Nov. 18, 2025)
V	Department, Order No. 202-25-8 (Aug. 28, 2025)
W	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E
X	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 (Tri-State, 2023 ERP Phase I, Rev. 2 (Apr. 22, 2024)

Y	CoPUC, *Verified Petition of Trial Staff of the Commission, CEO, UCA, and Public Service for a Variance from Decision No. C18-0761 and Any Other Requirements, Request for Shortened Notice and Intervention Period, and Request for Approval of Associated Procedures,* filed on November 10, 2025, in Proceeding No. 25V-0480E
Z	CoPUC, Tri-State, *2025 Annual Progress Report*, filed on December 1, 2025, in Proceeding No. 23A-0585E
AA	CoPUC, Decision No. R24-0602, issued on August 22, 2024, in Proceeding No. 23A-0585E
BB	CoPUC, Decision No. C25-0892, issued on December 10, 2020, in Proceeding No. 25V-0480E
CC	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1-Attachment F (*Electric Energy and Demand Forecast*, Public)
DD	CoPUC, Hrg. Ex. 103, Direct Testimony and Attachments of Brian L. Thompson, Rev. 1, filed on May 24, 2024, in Proceeding No. 23A-0585E
EE	PRPA, *2024 Integrated Resource Plan* (Apr. 2023)
FF	PRPA, *Craig Units 1&2 (Yampa Project)* (2026)
GG	PacifiCorp, *Utah Integrated Resource Plan Volume* I (Mar. 31, 2025)
HH	SPP, *SPP Reliability Plan* (Jun 2, 2025)
II	NERC, *Emergency Operations*
JJ	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Proceeding 20A-0528E
KK	Division, *Operating Permit No. 96OPMF155* (July 1, 2021)
LL	Division, *Technical Review Document for Operating Permit 96OPMF155* (Jan. 2005)
MM	Tri-State, *General APEN- Form APCD-200* (Apr. 21, 2025)
NN	Division, *Colorado Visibility and Regional Haze SIP for the Twelve Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016)
OO	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 – Attachment G-1 (Astrape Consulting, *Reserve Margin and Effective Load Carrying Capability (ELCC) Study*, Public (Aug. 2, 2023)
PP	Department, Order No. 202-25-10 (Nov. 25, 2025)
QQ	Tri-State, *U.S. DOE Orders TriState to Keep Craig Generating Station Unit Operating for Next 90 Days* (Dec. 31, 2025)
RR	Powell, R*., 1 coal plant open amid order* (Jan. 6, 2026)
SS	Behr, P., *PJM to ratchet down projected AI power demand for eastern US* (Jan. 6 , 2026)

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit DDD: Letter from Jerome H. Sturhahn, Senior Vice President of Tri-State, to Shannon McMillian, Compliance and Enforcement Program Manager, CDPHE (Jan. 26, 2026)

Docusign Envelope ID: A54195B0-BCB8-487F-9EF5-D05BE2F5A764

TRI-STATE

January 26, 2026

Submitted via email: cdphe_apcd_compliancetesting@state.co.us

Ms. Shannon McMillan
Compliance and Enforcement Program Manager
Colorado Department of Public Health and Environment
APCD-SS-B1
4300 Cherry Creek Drive South
Denver, Colorado 80246-1530

Re: Tri-State Generation and Transmission Association, Inc.
Craig Station Quarterly Mercury Reports: Fourth Quarter 2025

Dear Ms. McMillan:

Tri-State Generation and Transmission Association, Inc. (Tri-State) submits the enclosed low emitter mercury reports for Craig Station for the fourth quarter of 2025, in accordance with Colorado Regulation 6, Part B.

During the reporting quarter, Craig Unit 3 operated very few hours in contrast to historical unit operations. As a result, the reported monitor downtime percentage for the sorbent trap system is high.

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in the attached report is true, accurate and complete.

If you have any questions regarding these reports, please contact Marc Mayzes or me at 303-452-6111.

Sincerely,

Signed by:
Jerome H. Sturhahn
AFDDE2F9ABE741B...

Jerome H. Sturhahn
Senior Vice President,
General Counsel

JHS:MCM:BC

Enclosures

Files: G31-11.3(1)d-2e

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Low Emitter
Quarterly Mercury Report
Craig Unit 1
Fourth Quarter 2025

Hg Emitted in Quarter	**2.03**	Pounds
Hg Emitted Annually (end of calendar year)	**9.59**	Pounds
Quarterly Unit Operating Time	**1,736.20**	Hours
Quarterly Total Monitoring System Downtime	**77**	Hours
Quarterly Monitoring System Downtime	**4.43%**	%
Hg Monitoring Method Used (CEMS, Sorbent Trap, Performance Testing)	**CEMS**	
If CEMS or Sorbent Trap: Manufacturer, Model and Serial Number	**Tekran Series 3300 Serial Number 6082**	
If Sorbent Trap Analyzed Off-Site: Lab Used	**NA**	
Date of Last Relative Accuracy Test Audit (RATA) and Entity Performing Test	**RATA conducted June 16, 2025 by Montrose Environmental**	
Date of Last Linearity Test	**October 9, 2025**	
Were there any QA/QC activities that differed from the monitoring plan used in the last quarter? If yes, please briefly describe.[1]	**NO**	
Have there been any changes to the Mercury Monitoring Plan and/or QA/QC Plan since the last quarterly report? If yes, please briefly describe.	**NO**	

[1] Low Emitters are not required to have mercury monitoring plans or QA/QC plans. This information need only be provided in the event a Low Emitter chooses to use Hg CEMs. In such event, monitoring plan requirements are contained in both Regulation 6, Part B and 40 C.F.R. Part 75.

Docusign Envelope ID: A54195B0-BCB8-487F-9EF5-D05BE2F5A764

Downtime Events

Plant: CRAIG
Report Period: 10/01/2025 00:00 Through 12/31/2025 23:59
Time Online Criteria: 1 minute(s)

Source: UNIT1
Parameter: HGT
Interval: 001H

Event ID	Date/Time	Reason Code - Description
1	10/07/25 05:00	73 - 1d-Not enough data for valid hour
2	10/08/25 08:00	43 - 1d-Routine or scheduled maintenance
3	10/08/25 09:00	43 - 1d-Routine or scheduled maintenance
4	10/08/25 10:00	43 - 1d-Routine or scheduled maintenance
5	10/08/25 11:00	43 - 1d-Routine or scheduled maintenance
6	10/08/25 12:00	43 - 1d-Routine or scheduled maintenance
7	10/14/25 05:00	73 - 1d-Not enough data for valid hour
8	10/16/25 09:00	73 - 1d-Not enough data for valid hour
9	10/21/25 05:00	73 - 1d-Not enough data for valid hour
10	10/28/25 05:00	73 - 1d-Not enough data for valid hour
11	11/04/25 04:00	69 - 1d-Previous integrity check expired
12	11/04/25 05:00	69 - 1d-Previous integrity check expired
13	11/04/25 06:00	69 - 1d-Previous integrity check expired
14	11/04/25 07:00	69 - 1d-Previous integrity check expired
15	11/04/25 08:00	69 - 1d-Previous integrity check expired
16	11/04/25 09:00	69 - 1d-Previous integrity check expired
17	11/04/25 10:00	69 - 1d-Previous integrity check expired
18	11/04/25 11:00	69 - 1d-Previous integrity check expired
19	11/04/25 12:00	69 - 1d-Previous integrity check expired
20	11/04/25 13:00	69 - 1d-Previous integrity check expired
21	11/04/25 14:00	69 - 1d-Previous integrity check expired
22	11/04/25 15:00	69 - 1d-Previous integrity check expired
23	11/04/25 16:00	69 - 1d-Previous integrity check expired
24	11/04/25 17:00	69 - 1d-Previous integrity check expired
25	11/04/25 18:00	69 - 1d-Previous integrity check expired
26	11/04/25 19:00	69 - 1d-Previous integrity check expired
27	11/04/25 20:00	69 - 1d-Previous integrity check expired
28	11/11/25 05:00	37 - 1c-Quality assurance check
29	11/18/25 05:00	37 - 1c-Quality assurance check
30	11/18/25 11:00	27 - 1b-Monitor component malfunction
31	11/18/25 12:00	27 - 1b-Monitor component malfunction
32	11/18/25 14:00	27 - 1b-Monitor component malfunction
33	11/18/25 15:00	27 - 1b-Monitor component malfunction
34	11/18/25 16:00	27 - 1b-Monitor component malfunction
35	11/18/25 17:00	27 - 1b-Monitor component malfunction
36	11/18/25 18:00	27 - 1b-Monitor component malfunction
37	11/18/25 19:00	27 - 1b-Monitor component malfunction
38	11/18/25 20:00	27 - 1b-Monitor component malfunction
39	11/18/25 21:00	27 - 1b-Monitor component malfunction
40	11/18/25 22:00	27 - 1b-Monitor component malfunction
41	11/18/25 23:00	27 - 1b-Monitor component malfunction
42	11/19/25 00:00	27 - 1b-Monitor component malfunction
43	11/19/25 01:00	27 - 1b-Monitor component malfunction

Docusign Envelope ID: A54195B0-BCB8-487F-9EF5-D05BE2F5A764

Downtime Events

Plant: CRAIG
Report Period: 10/01/2025 00:00 Through 12/31/2025 23:59
Time Online Criteria: 1 minute(s)

Source: UNIT1
Parameter: HGT
Interval: 001H

Event ID	Date/Time	Reason Code - Description
44	11/19/25 02:00	27 - 1b-Monitor component malfunction
45	11/19/25 03:00	27 - 1b-Monitor component malfunction
46	11/19/25 04:00	27 - 1b-Monitor component malfunction
47	11/19/25 05:00	27 - 1b-Monitor component malfunction
48	11/19/25 10:00	27 - 1b-Monitor component malfunction
49	11/19/25 11:00	27 - 1b-Monitor component malfunction
50	11/19/25 12:00	27 - 1b-Monitor component malfunction
51	11/25/25 05:00	37 - 1c-Quality assurance check
52	12/01/25 05:00	47 - 1b-Sampling system problem
53	12/01/25 06:00	47 - 1b-Sampling system problem
54	12/01/25 07:00	47 - 1b-Sampling system problem
55	12/01/25 08:00	47 - 1b-Sampling system problem
56	12/01/25 09:00	47 - 1b-Sampling system problem
57	12/01/25 10:00	47 - 1b-Sampling system problem
58	12/01/25 11:00	47 - 1b-Sampling system problem
59	12/01/25 12:00	47 - 1b-Sampling system problem
60	12/01/25 13:00	47 - 1b-Sampling system problem
61	12/02/25 05:00	37 - 1c-Quality assurance check
62	12/04/25 05:00	47 - 1b-Sampling system problem
63	12/04/25 06:00	47 - 1b-Sampling system problem
64	12/04/25 07:00	47 - 1b-Sampling system problem
65	12/10/25 10:00	27 - 1b-Monitor component malfunction
66	12/10/25 11:00	27 - 1b-Monitor component malfunction
67	12/10/25 12:00	27 - 1b-Monitor component malfunction
68	12/10/25 13:00	27 - 1b-Monitor component malfunction
69	12/10/25 14:00	27 - 1b-Monitor component malfunction
70	12/10/25 15:00	27 - 1b-Monitor component malfunction
71	12/10/25 16:00	27 - 1b-Monitor component malfunction
72	12/10/25 17:00	27 - 1b-Monitor component malfunction
73	12/10/25 18:00	27 - 1b-Monitor component malfunction
74	12/10/25 19:00	27 - 1b-Monitor component malfunction
75	12/10/25 20:00	27 - 1b-Monitor component malfunction
76	12/16/25 05:00	73 - 1d-Not enough data for valid hour
77	12/17/25 11:00	73 - 1d-Not enough data for valid hour

Number of Events: 77

Docusign Envelope ID: A54195B0-BCB8-487F-9EF5-D05BE2F5A764

Low Emitter
Quarterly Mercury Report
Craig Unit 2
Fourth Quarter 2025

Hg Emitted in Quarter	**3.04**	Pounds
Hg Emitted Annually (end of calendar year)	**10.78**	Pounds
Quarterly Unit Operating Time	**2,207.27**	Hours
Quarterly Total Monitoring System Downtime	**22**	Hours
Quarterly Monitoring System Downtime	**1.00 %**	%
Hg Monitoring Method Used (CEMS, Sorbent Trap, Performance Testing)	**CEMS**	
If CEMS or Sorbent Trap: Manufacturer, Model and Serial Number	**Tekran Series 3300 Serial Number 6083**	
If Sorbent Trap Analyzed Off-Site: Lab Used	**NA**	
Date of Last Relative Accuracy Test Audit (RATA) and Entity Performing Test	**RATA conducted June 17, 2024 by Montrose Environmental**	
Date of Last Linearity Test	**October 8, 2025**	
Were there any QA/QC activities that differed from the monitoring plan used in the last quarter? If yes, please briefly describe.[1]	**NO**	
Have there been any changes to the Mercury Monitoring Plan and/or QA/QC Plan since the last quarterly report? If yes, please briefly describe.	**NO**	

Docusign Envelope ID: A54195B0-BCB8-487F-9EF5-D05BE2F5A764

Downtime Events

Plant: CRAIG
Report Period: 10/01/2025 00:00 Through 12/31/2025 23:59
Time Online Criteria: 1 minute(s)

Source: UNIT2
Parameter: HGT
Interval: 001H

Event ID	Date/Time	Reason Code - Description
1	10/07/25 04:00	26 - 1d - Recovery following calibration
2	10/07/25 08:00	43 - 1d-Routine or scheduled maintenance
3	10/07/25 09:00	43 - 1d-Routine or scheduled maintenance
4	10/07/25 10:00	26 - 1d - Recovery following calibration
5	10/07/25 12:00	43 - 1d-Routine or scheduled maintenance
6	10/07/25 13:00	43 - 1d-Routine or scheduled maintenance
7	10/14/25 04:00	26 - 1d - Recovery following calibration
8	10/21/25 04:00	26 - 1d - Recovery following calibration
9	10/21/25 05:00	26 - 1d - Recovery following calibration
10	10/21/25 06:00	26 - 1d - Recovery following calibration
11	10/28/25 03:00	69 - 1d-Previous integrity check expired
12	10/28/25 04:00	69 - 1d-Previous integrity check expired
13	10/28/25 05:00	69 - 1d-Previous integrity check expired
14	10/28/25 06:00	69 - 1d-Previous integrity check expired
15	11/04/25 05:00	26 - 1d - Recovery following calibration
16	11/11/25 05:00	26 - 1d - Recovery following calibration
17	11/18/25 05:00	26 - 1d - Recovery following calibration
18	11/25/25 05:00	26 - 1d - Recovery following calibration
19	12/02/25 05:00	26 - 1d - Recovery following calibration
20	12/16/25 05:00	26 - 1d - Recovery following calibration
21	12/23/25 05:00	26 - 1d - Recovery following calibration
22	12/30/25 05:00	26 - 1d - Recovery following calibration

Number of Events: 22

Docusign Envelope ID: A54195B0-BCB8-487F-9EF5-D05BE2F5A764

Low Emitter
Quarterly Mercury Report
Craig Unit 3
Fourth Quarter 2025

Hg Emitted in Quarter	**0.01**	Pounds
Hg Emitted Annually (end of calendar year)	**2.34**	Pounds
Quarterly Unit Operating Time	**51.33**	Hours
Quarterly Total Monitoring System Downtime	**22**	Hours
Quarterly Monitoring System Downtime	**42.86 %**	%
Hg Monitoring Method Used (CEMS, Sorbent Trap, Performance Testing)	**Sorbent Traps**	
If CEMS or Sorbent Trap: Manufacturer, Model and Serial Number	**Environmental Supply Model Hg-324K Serial Numbers 1036 & 1043**	
If Sorbent Trap Analyzed Off-Site: Lab Used	**Ohio Lumex**	
Date of Last Relative Accuracy Test Audit (RATA) and Entity Performing Test	**RATA's conducted June 20, 2025 on console #1036 and June 19, 2025 on console #1043 by Montrose Environmental**	
Were there any QA/QC activities that differed from the monitoring plan used in the last quarter? If yes, please briefly describe.[1]	**NO**	
Have there been any changes to the Mercury Monitoring Plan and/or QA/QC Plan since the last quarterly report? If yes, please briefly describe.	**NO**	

Docusign Envelope ID: A54195B0-BCB8-487F-9EF5-D05BE2F5A764

Downtime Events

Plant: CRAIG
Report Period: 10/01/2025 00:00 Through 12/31/2025 23:59
Time Online Criteria: 1 minute(s)

Source: UNIT3
Parameter: HG#/GWHR
Interval: 001H

Event ID	Date/Time	Reason Code - Description
1	11/25/25 13:00	19 - 1d - Missing non mercury component for calculation
2	11/25/25 14:00	19 - 1d - Missing non mercury component for calculation
3	11/25/25 15:00	19 - 1d - Missing non mercury component for calculation
4	11/25/25 16:00	19 - 1d - Missing non mercury component for calculation
5	11/25/25 17:00	19 - 1d - Missing non mercury component for calculation
6	11/25/25 18:00	19 - 1d - Missing non mercury component for calculation
7	11/25/25 19:00	19 - 1d - Missing non mercury component for calculation
8	11/25/25 20:00	19 - 1d - Missing non mercury component for calculation
9	11/25/25 21:00	19 - 1d - Missing non mercury component for calculation
10	11/25/25 22:00	19 - 1d - Missing non mercury component for calculation
11	12/30/25 04:00	19 - 1d - Missing non mercury component for calculation
12	12/30/25 05:00	19 - 1d - Missing non mercury component for calculation
13	12/30/25 06:00	19 - 1d - Missing non mercury component for calculation
14	12/30/25 07:00	19 - 1d - Missing non mercury component for calculation
15	12/30/25 08:00	19 - 1d - Missing non mercury component for calculation
16	12/30/25 09:00	19 - 1d - Missing non mercury component for calculation
17	12/30/25 10:00	19 - 1d - Missing non mercury component for calculation
18	12/30/25 19:00	19 - 1d - Missing non mercury component for calculation
19	12/31/25 01:00	19 - 1d - Missing non mercury component for calculation
20	12/31/25 03:00	19 - 1d - Missing non mercury component for calculation
21	12/31/25 04:00	19 - 1d - Missing non mercury component for calculation
22	12/31/25 19:00	19 - 1d - Missing non mercury component for calculation
	Number of Events: 22	

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit EEE: CoPUC, Tri-State, Notice Regarding Phase II Developments,
filed on March 17, 2026, in Proceeding No. 23A-0585E

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

IN THE MATTER OF THE APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN	)))))))	**PROCEEDING NO. 23A-0585E**

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.'S NOTICE REGARDING PHASE II DEVELOPMENTS

Tri-State Generation and Transmission Association, Inc. ("Tri-State"), through its undersigned legal counsel, respectfully submits this notice pertaining to certain developments related to its 2023 Electric Resource Plan. In particular, Tri-State is providing updates on:

1. Acquisition of resources in connection with the Commission's Phase II Decision; and
2. The status of the federal funding Tri-State requested from the United States Department of Agriculture's ("USDA") under the Empowering Rural America ("New ERA") program.

I. BACKGROUND

1. On December 1, 2023, Tri-State filed Phase I of its 2023 Electric Resource Plan ("ERP") in Proceeding No. 23A-0585E. The Phase I issues were resolved by an Unopposed Comprehensive Settlement Agreement ("Phase I Settlement") among all parties, which was approved in Decision No. R24-0602 filed on August 22, 2024.

Colorado PUC E-Filings System

2. Among other provisions, the Phase I Settlement[1] confirmed the planned retirement dates for Tri-State's remaining coal units, including Craig Unit 3 (January 1, 2028) and Springerville Unit 3 ("SPV 3") (September 15, 2031), as reasonable. The Phase I Settlement acknowledged that SPV 3's 2031 retirement was contingent upon Tri-State securing funding as requested under the federal New ERA program and negotiating the resolution of contractual agreements impacted by the unit's retirement.[2]

3. Tri-State conducted competitive solicitations for new resources pursuant to the approved Phase I plan. On April 11, 2025, Tri-State filed its Phase II ERP Implementation Report, presenting several modeled portfolios and identifying a preferred portfolio (designated "Portfolio 4 – FLEX Shafer Replacement" or "FLEXSR") of ten selected bids for Commission approval. The preferred portfolio consisted of approximately 700 MW of new wind and solar generation, 650 MW of battery storage, and 307 MW of gas-fired generation to be acquired between 2026 and 2031.

4. In its Phase II Decision,[3] the Commission approved Tri-State's preferred portfolio (FLEXSR) as the approved cost-effective resource plan.

II. UPDATE ON NEW RESOURCE ACQUISITION

5. Tri-State has made substantial progress toward implementing the Phase II resource acquisitions. Tri-State provided an update on Phase II resource acquisitions in its December 1, 2025 Annual Progress Report. To date, Tri-State has executed contracts for 200 MW of wind generation, 100 MW of solar generation, and 550 MW of battery

[1] Appendix A to Decision No. R24-0602 (Aug. 22, 2024).
[2] The Settlement Agreement states that "[t]he Settling Parties agree that the Commission should approve a Springerville 3 retirement date of September 15, 2031 **subject to New ERA funding award as requested** from USDA and **successful Tri-State negotiation of contractual agreements impacted by the unit's retirement**."
[3] Decision No. C25-0612 (Aug. 26, 2025) (as modified in part on rehearing in Decision No. C25-0740 (Oct. 9, 2025).

storage from the preferred portfolio bid selections. In particular, Tri-State has executed contracts for the following projects:

- High Country Energy Station 2 (Montrose County, CO), 50 MW, Q2 2027 COD;
- Oso Negro Energy Storage (Bernalillo County, NM), 100 MW, Q2 2028 COD;
- Morel Energy Storage (Moffat County, CO), 200 MW, Q1-2030 COD;
- Carousel Surplus Energy Storage (Kit Carson County, CO), 150 MW, Q4 2027 COD;
- Arriba Wind (Lincoln County, CO), 200 MW, Q1 2029 COD; and
- Alamogordo Solar and Storage (Otero County, NM), 100 MW Solar and 50 MW Storage, Q2 2028 COD.

6. These contracted projects, which are drawn from the Phase II preferred bids, represent the majority of the storage capacity and a portion of the wind capacity in the approved portfolio.

7. Tri-State is continuing its procurement efforts for some, but not all, remaining approved resources. In particular, Tri-State is not anticipating execution of contracts for certain originally selected bids and is instead evaluating alternative options for these needs. The following projects are not anticipated to be brought under contract due to the developers not posting bid security and facing pricing and feasibility issues:

- WI-0013-2-WYO-WNE (Wyoming), 200 MW Wind, Q1 2030 COD; and
- GG-0006-2-WCO (Moffat County, CO), 307 MW Gas, Q3 2028 COD.

8. Tri-State is delaying pursuit of back-up bids for these resources until further certainty regarding New ERA program funding is attained, as discussed below.

9. Tri-State is continuing to pursue the remaining solar and storage bids that were selected in its preferred portfolio. The Carousel Surplus Energy Storage project was increased in size from the original bid, by 50 MW, and the remaining storage bid may also have potential to increase in size from the original bid, by 50 MW. These changes help to narrow the gap on remaining project procurements from the 2023 ERP Phase II process.

10. Tri-State will be filing an updated load and resources table in Proceeding No. 26M-0028E to reflect the developments described in this Notice pursuant to §40-43-104(1)(a), C.R.S., as required, by April 1, 2026.

III. UPDATE REGARDING FEDERAL FUNDING

11. As described in previous filings, Tri-State pursued federal support for certain ERP-related activities under the USDA New ERA program to assist rural electric cooperatives in financing clean energy investments.

12. Tri-State's New ERA application was selected for an award. Tri-State executed commitment letters with the USDA for the New ERA award in late 2024 and early 2025 and began preliminary planning to utilize the funds.

13. On January 27, 2025, the incoming administration issued a directive halting the implementation of certain programs, including New ERA grants, pending further review. USDA subsequently released the funding on March 25, 2025,[4] however, as of the date of this Notice, Tri-State has not obtained certainty regarding the timing of release of its award funds.

[4] *See* USDA Press Release No. 0061-25 (March 25, 2025), available at https://www.usda.gov/about-usda/news/press-releases/2025/03/25/usda-delivers-rural-energy-commitments-provides-path-applicants-support-us-energy-independence.

14. Tri-State will file an update on the status of 2023 ERP Phase II procurements and New ERA funding no later than June 30, 2026, within this proceeding.

Dated this 17th day of March, 2026.

WOMBLE BOND DICKINSON (US) LLP

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Attorneys for Tri-State Generation and Transmission Association, Inc

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit FFF: SPP, Current Grid Conditions (Apr. 7, 2026)

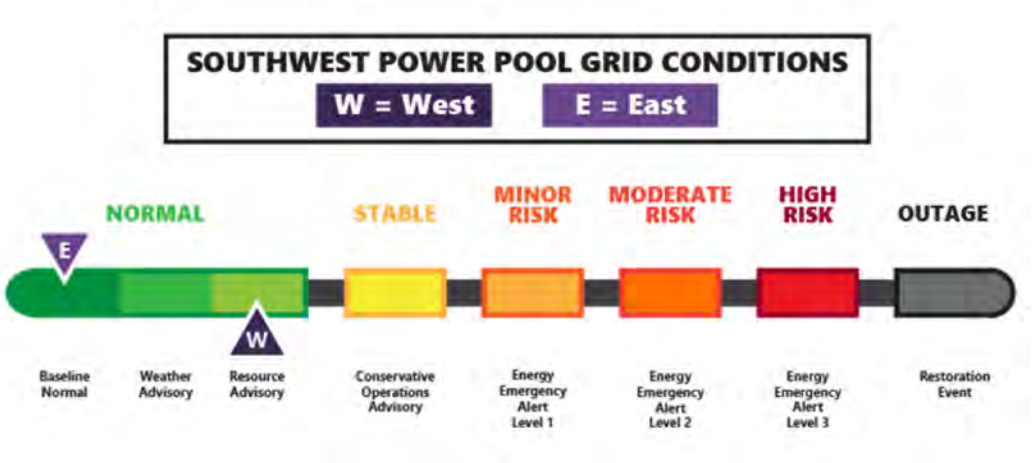


CURRENT GRID CONDITIONS

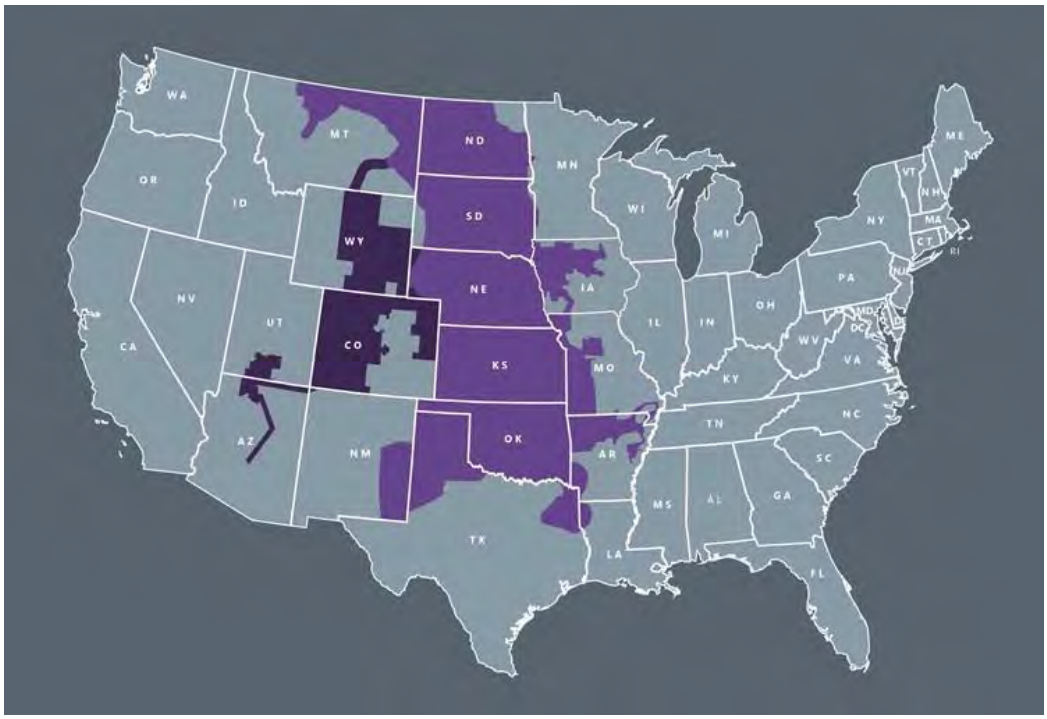
Updated Tuesday, April 7, 2026, at 12:55 p.m. CT

SPP is issuing a Resource Advisory for the West Balancing Authority (BA) area, effective Wednesday, April 8, 12:00 a.m. CT until an anticipated end time of Monday, April 13, at 12:00 a.m. CT. Resource Advisories are still considered Normal Operating Conditions, and do not require the public to conserve energy or take any action, but are issued to raise awareness of potential threats to reliability among entities responsible for operating transmission and generation facilities.

SPP's East BA area remains under normal operating conditions. Find a map of SPP's East and West BA areas below.



- This Resource Advisory in SPP's West BA area is being declared due to load uncertainty, increased potential for low output from wind and other variable energy resources (*also known as low VER forecast) leading into peak hours, and potential for resource outages.
- Individuals should contact their local utility for details specific to their area.
- Generation and transmission operators have been provided instructions on applicable procedures, including reporting any limitations, fuel shortages or concerns.
- To mitigate risks to reliability associated with these factors, SPP may use greater unit commitment notification timeframes, including making commitments before standard day-ahead market procedures and/or committing resources in reliability status.
- SPP will send additional information if necessary.



Descriptions of common reliability events are provided below in increasing order of severity:

Advisories raise awareness and do not require general audiences to take action. SPP member utilities should follow applicable procedures. Energy Emergency Alerts indicate all available generation has been committed to meet region-wide demand. As conditions worsen, voluntary conservation or service interruptions may be necessary to prevent uncontrolled outages.

Normal Operations: SPP has enough generation to meet demand and available reserves, and it foresees no extreme or abnormal threats to reliability.

Weather Advisory: Declared when extreme weather is expected in SPP's reliability coordination service territory.

Resource Advisory: Declared when severe weather conditions, significant outages, wind-forecast uncertainty and/or load-forecast uncertainty are expected in SPP's balancing authority area.

Conservative Operations Advisory: Declared when SPP determines there is a need to operate its system conservatively based on weather, environmental, operational, terrorist, cyber or other events.

Energy Emergency Alert Level 1: Declared when all available resources have been committed to meet obligations, and SPP is at risk of not meeting required operating reserves.

Energy Emergency Alert Level 2: Declared when SPP can no longer provide expected energy requirements, or when SPP foresees or has implemented procedures up to, but excluding, service interruptions to maintain regional reliability.

Energy Emergency Alert Level 3: At this level, SPP is utilizing operating reserves such that it is carrying reserves below the required minimum and has initiated assistance through its Reserve Sharing Group. SPP foresees or has implemented firm load obligation interruption. Before requesting an EEA 3, SPP will have already provided the appropriate internal notifications to its Market Participants.

Restoration Event: Defined as a major or catastrophic grid outage which could be a total or partial regional blackout, island situation or system separation.

To receive updates about changing grid conditions via email, subscribe to SPP's Grid Notice exploder:

- Once logged into SPP.org, click the "Hi, [your name]" button in the top right of the screen to update your account preferences. (You may have to create an account if you don't already have one.)
- In the list of available exploders, check the box next to the one named "Grid Notice."
- Click "Submit" at the bottom of the form to save your changes.
- *You can unsubscribe from this and other exploders at any time on the same account management page.*

MARKETS & OPERATIONS

- Advancing Technology
- Current Grid Conditions
  - 2021 Winter Storm Review
  - December 2022 Winter Storm Review
- SPP Portal
- Market Monitoring
- Net Benefits Test
- Operating Reliability
- Outage Coordination
- Revision Requests
- TCR Markets
- Go to SPP Portal
- OASIS
- High Impact Large Load (HILL) Integration

RELATED DOCUMENTS

Emergency Communications Channels and Procedures

Stakeholder Groups

Meeting materials, member info, and more.

Documents

Filings, governing documents, and other resources.

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Latest company news and media contacts.

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(501) 614-3200

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

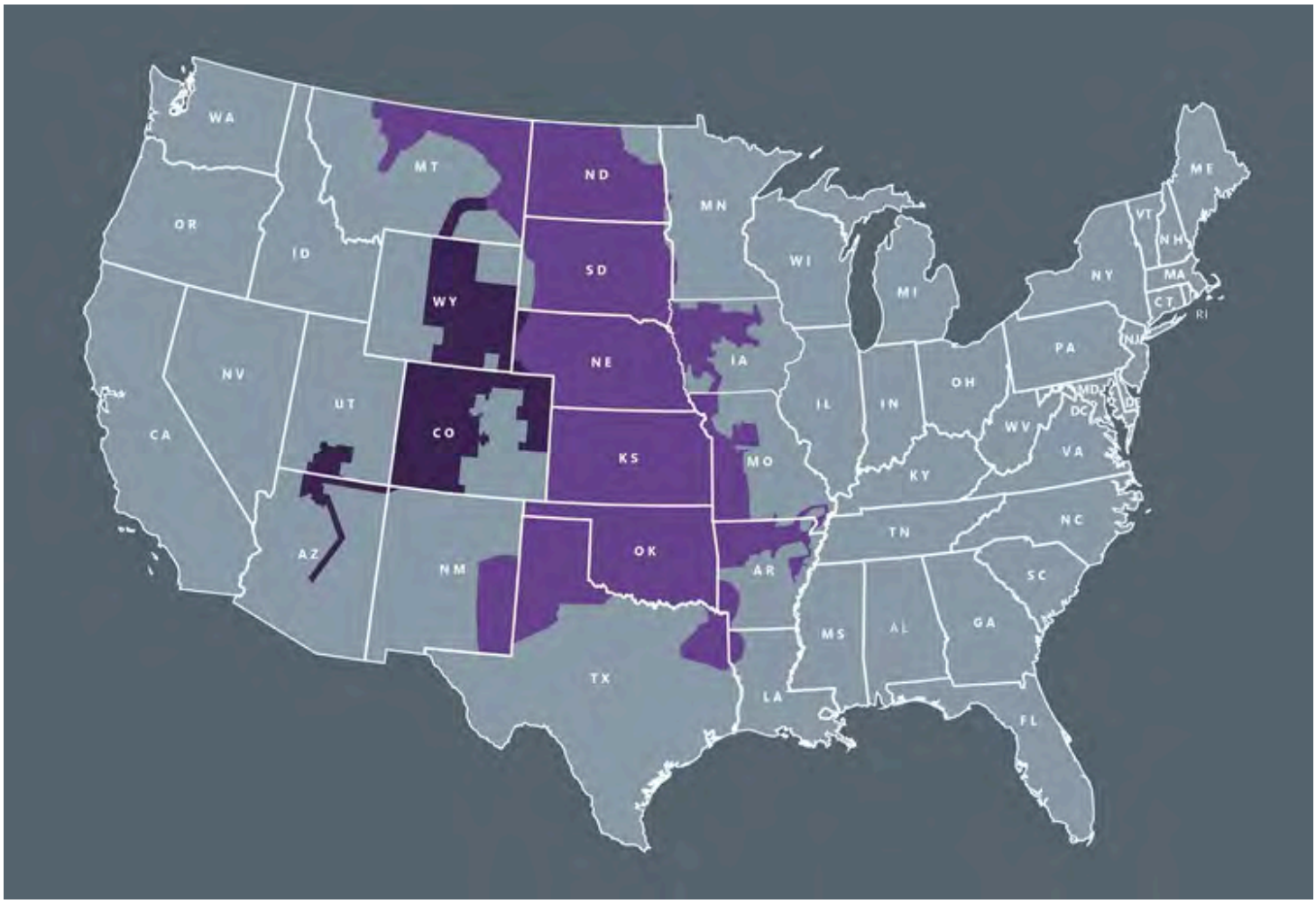
The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit GGG: SPP, Current Grid Conditions (Apr. 20, 2026)



CURRENT GRID CONDITIONS

The entire SPP footprint in the East and West Balancing Authority (BA) areas is currently operating under normal grid conditions.



Updated as of Monday, April 20, 2026

SPP is extending the Resource Advisory for the West Balancing Authority (BA) area through an anticipated end time of Friday, April 24, at 5:00 p.m. CT. ***Resource Advisories are still considered normal operating conditions, and do not require the public to conserve energy or take any action,*** *but are issued to raise awareness of potential threats to reliability among entities responsible for operating transmission and generation facilities.*

- **This Resource Advisory in SPP's West BA area is being extended due to load uncertainty, increased potential for low output from wind and other variable energy resources (*also known as low VER forecast) leading into peak hours, and potential for resource outages.**
- Individuals should contact their local utility for details specific to their area.
- Generation and transmission operators have been provided instructions on applicable procedures, including reporting any limitations, fuel shortages or concerns.
- To mitigate risks to reliability associated with these factors, SPP may use greater unit commitment notification timeframes, including making commitments before standard day-ahead market procedures and/or committing resources in reliability status.
- SPP will send additional information if necessary.
- This Resource Advisory for SPP's West Balancing Authority (BA) went into effect Wednesday, April 15, at 5:00 a.m. CT.

Updated as of Tuesday, April 14, 2026

SPP has issued a Resource Advisory for the West Balancing Authority (BA) area, effective Wednesday, April 15, as of 5:00 a.m. CT until an anticipated end time of Tuesday, April 21, at 12:00 a.m. CT. Resource Advisories are still considered normal operating conditions, and do not require the public to conserve energy or take any action, but are issued to raise awareness of potential threats to reliability among entities responsible for operating transmission and generation facilities.

- This Resource Advisory in SPP's West BA area is being declared due to load uncertainty, increased potential for low output from wind and other variable energy resources (*also known as low VER forecast) leading into peak hours, and potential for resource outages.
- Individuals should contact their local utility for details specific to their area.
- Generation and transmission operators have been provided instructions on applicable procedures, including reporting any limitations, fuel shortages or concerns.
- To mitigate risks to reliability associated with these factors, SPP may use greater unit commitment notification timeframes, including making commitments before standard day-ahead market procedures and/or committing resources in reliability status.
- SPP will send additional information if necessary.

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Updated as of Tuesday, April 7, 2026

SPP is issuing a Resource Advisory for the West Balancing Authority (BA) area, effective Wednesday, April 8, 12:00 a.m. CT until an anticipated end time of Monday, April 13, at 12:00 a.m. CT. Resource Advisories are still considered Normal Operating Conditions, and do not require the public to conserve energy or take any action, but are issued to raise awareness of potential threats to reliability among entities responsible for operating transmission and generation facilities.

- This Resource Advisory in SPP's West BA area is being declared due to load uncertainty, increased potential for low output from wind and other variable energy resources (*also known as low VER forecast) leading into peak hours, and potential for resource outages.
- Individuals should contact their local utility for details specific to their area.
- Generation and transmission operators have been provided instructions on applicable procedures, including reporting any limitations, fuel shortages or concerns.
- To mitigate risks to reliability associated with these factors, SPP may use greater unit commitment notification timeframes, including making commitments before standard day-ahead market procedures and/or committing resources in reliability status.
- SPP will send additional information if necessary.

Descriptions of common reliability events are provided below in increasing order of severity:

Advisories raise awareness and do not require general audiences to take action. SPP member utilities should follow applicable procedures. Energy Emergency Alerts indicate all available generation has been committed to meet region-wide demand. As conditions worsen, voluntary conservation or service interruptions may be necessary to prevent uncontrolled outages.

Normal Operations: SPP has enough generation to meet demand and available reserves, and it foresees no extreme or abnormal threats to reliability.

Weather Advisory: Declared when extreme weather is expected in SPP's reliability coordination service territory.

Resource Advisory: Declared when severe weather conditions, significant outages, wind-forecast uncertainty and/or load-forecast uncertainty are expected in SPP's balancing authority area.

Conservative Operations Advisory: Declared when SPP determines there is a need to operate its system conservatively based on weather, environmental, operational, terrorist, cyber or other events.

Energy Emergency Alert Level 1: Declared when all available resources have been committed to meet obligations, and SPP is at risk of not meeting required operating reserves.

Energy Emergency Alert Level 2: Declared when SPP can no longer provide expected energy requirements, or when SPP foresees or has implemented procedures up to, but excluding, service interruptions to maintain regional reliability.

Energy Emergency Alert Level 3: At this level, SPP is utilizing operating reserves such that it is carrying reserves below the required minimum and has initiated assistance through its Reserve Sharing Group. SPP foresees or has implemented firm load obligation interruption. Before requesting an EEA 3, SPP will have already provided the appropriate internal notifications to its Market Participants.

Restoration Event: Defined as a major or catastrophic grid outage which could be a total or partial regional blackout, island situation or system separation.

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- Once logged into SPP.org, click the "Hi, [your name]" button in the top right of the screen to update your account preferences. (You may have to create an account if you don't already have one.)
- In the list of available exploders, check the box next to the one named "Grid Notice."
- Click "Submit" at the bottom of the form to save your changes.
- *You can unsubscribe from this and other exploders at any time on the same account management page.*

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit HHH: Cook, A., NERC to OMS: Long-term Assessment not a Predictor of Risk
(Feb. 10, 2026)

This is your first of five complimentary articles.

NERC to OMS: Long-term Assessment not a Predictor of Risk

Listen to this story (#/)



(//www.rtoinsider.com/125429-nerc-oms-long-term-assessment-not-predictor-risk/)

A rendering of Invenergy's proposed 1.2-GW simple-cycle gas plant in Kenosha County, Wis. The project is in MISO's interconnection fast track. | *Invenergy*

NERC (https://www.rtoinsider.com/category/ero/ero-nerc-committees/) officials appeared before an Organization of *MISO (https://www.rtoinsider.com/category/rto/rto-miso/)* States board meeting in an attempt to quell regulators' discontent with MISO's "high-risk" label in the 2025 Long-Term Reliability Assessment.

"I think we understand your concerns," said NERC CEO James Robb, who referred to "anxiety" around the exclusion of MISO's interconnection queue fast track in the LTRA. He said the LTRA "is not a prediction in any way."

"It's a risk assessment," he told regulatory staff members at a Feb. 9 Organization of MISO States board meeting.

NERC *found (https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf)* that by winter 2028/29, MISO would struggle with reliability under normal conditions. Some state regulators bristled at the designation and criticized the assessment for not including MISO's expedited generator interconnection process and the projects in it.

The Takeaway

NERC told MISO state regulators that its Long-Term Reliability Assessment isn't a predictor of what's to come, though it's often construed that way.

Regulators also said NERC's conclusion essentially ignores that most MISO states must plan resources in accordance with state law and that MISO measures its reserve margins differently from in NERC assumptions. (See *MISO States Dispute 'High Risk' Designation from NERC (https://www.rtoinsider.com/125208-miso-states-dispute-high-risk-designation-from-nerc/)*.)

Robb said this year's findings in the LTRA are a product of load growing faster than resources can be added or steadily dropping resource inventories. He said NERC is seeing "more and more" regions move into elevated reliability risk. "It's been growing and growing in severity," Robb said.

But over the years, he said, areas designated as "normal" in the LTRA have experienced emergency shortages while areas labeled "high risk" have pulled through difficult episodes.

Robb said the emergence of winter-peaking circumstances in the LTRA is due to an increasing deployment of solar generation suppressing the summer peak.

"Solar's a hell of a resource. It doesn't do a lot for you in winter," he said.

He also said NERC has in recent years found more limits overall with generators and resources that have become especially susceptible in winter.

John Moura, NERC director of reliability assessment and system analysis, explained the data collection deadline that left off generation proposals in MISO's interconnection queue fast lane. He said NERC must cut data collection off in summer to release the assessment. The deadline helps NERC understand which

resources are firm and deliverable by transmission, Moura said.

Moura said time and again, NERC sees the most certain, "Tier 1" generation projects fail to meet stated in-service dates.

"So, expecting 20 GW and getting 10 GW. We really are seeing half the resources come in on time," Moura said. "It's not an indictment; it's not a prediction. We are trying to showcase the risk … to stimulate the action needed."

Moura said the industry is learning that the "individual, isolated planning that got us a long way is breaking down a bit." He said neighboring regions need to understand one another's systems more. NERC strives to provide a "bedrock," he said, by using consistent assumptions.

Wisconsin Public Service Commissioner Marcus Hawkins cautioned NERC officials about assuming all new load at speed is gospel. He pointed out that the utilities reporting load additions stand to benefit from the boosted demand. He told NERC to be careful "if all upstream assumptions are from people with vested interests."

Michigan Public Service Commission Chair Dan Scripps said it feels like states in an RTO get "picked on" because even though most states in MISO are vertically integrated and have the same state-level mandates to maintain resource adequacy, they nevertheless are coded red.

South Dakota Public Utilities Commissioner Chris Nelson asked NERC officials if they think the LTRA is read as a prediction by the public.

Robb said it "certainly seems" the LTRA is construed that way "despite our best efforts." He added NERC hopes to "raise the flag" about getting more infrastructure built, and "not the old-fashioned way." He said grid expansion is going to take changes to permitting and siting processes.

MISO Senior Manager of Market Design Neil Shah said at a Feb. 10 Entergy Regional State Committee meeting that MISO is in contact with NERC to try to improve assumptions used in the LTRA.

Shah said including the generator interconnection express lane likely would "close the gap" in the NERC report. However, he said uncertainty remains due to the potential for more large loads claiming spots on the grid.

MISO expects the first projects from its expedited generator queue to come online in 2028, Shah said. Beyond that, Shah said "MISO is projecting higher rate of new resource additions in 2026" than have historically come online annually from 2022 to 2025.

"It incorporates a lot of things that we don't necessarily agree with," Bill Booth, a consultant to the Mississippi Public Service Commission, said of the assessment. He added that in addition to the expedited queue omission, NERC didn't factor in the trio of coal plants in MISO kept online via the U.S. Department of Energy's emergency orders under the Federal Power Act's Section 202(c).

MISO Promotes Stakeholder Involvement in Reworking NERC RA Standard

Meanwhile, MISO has encouraged its stakeholders to participate in NERC's development of a new energy assurance draft standard after it scrapped the first draft.

MISO's Zhaoxia Xie said at the January Reliability Subcommittee meeting that stakeholders should get involved. The reliability corporation's first draft of a proposed planning energy assurance standard *failed (https://sbs.nerc.net/BallotResults/Index/1060)* to get enough votes in support to advance. NERC's standard drafting team is assessing next steps and is planning a technical workshop Feb. 17 and meetups Feb. 18 and 19 to start revisions.

MISO regulators panned NERC's first attempt at a new resource adequacy standard over 2025. They said it would have infringed on states' grid planning authority. (See *MISO States Call NERC's Planned RA Standard Inappropriate (https://www.rtoinsider.com/119393-miso-states-say-nerc-planned-ra-standard-inappropriate/)*.)

NERC's original design would have had planning coordinators conducting their own Long-Term Energy Reliability Assessments using an unserved energy basis and reporting the results to NERC. Resource planners and transmission planners then would have to prove they developed corrective action plans — enforced by the ERO — to address "unacceptable" levels of reliability risks in long-term assessments.

"MISO is being open-minded and working with NERC to move along this effort," Xie said.

Minnesota Power's Tom Butz said it seems the NERC effort is entering "uncharted territory" and that a draft standard could be an opportunity to view system reliability in a new way. Butz asked that the RASC plan for "hands-on interplay" with the NERC docket as it's drafted.

Xie said MISO doesn't plan to schedule stakeholder discussion on the standard "because the project is not moving as fast" as originally thought.

MISO staff also said the RTO already covers or exceeds what the standard originally intended to include; they said even the draft standard wouldn't push its modeling into unfamiliar ground.

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit III: Brown, C., Plumer, B., Trump Wants to Halt Almost All Coal Plant Shutdowns. It Could be Messy (Jan. 16, 2026)

Trump Wants to Halt Almost All Coal Plant Shutdowns. It Could Get Messy.

Even as administration officials vowed this week to head off scheduled retirements, some aging plants are now breaking, and costs could run to the billions.

Listen · 11:35 min




By Claire Brown and Brad Plumer

Jan. 16, 2026

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Over the past eight months, the Energy Department has taken the extraordinary step of ordering that generators at five coal-burning power plants that had been headed for retirement stay open and keep running.

That's just the beginning, officials say.

At a White House event on Thursday, Trump administration officials said they planned to keep open as many coal plants as they could and prevent any further retirements over the next three years.

"The goal is to stop the political closure of coal plants," Chris Wright, the energy secretary, said during the first meeting of the National Coal Council, which had lapsed under the Biden administration but which President Trump has revived. Dozens of representatives from the coal industry were present.

The moves are part of a sweeping plan by Mr. Trump to revive America's coal industry, which has been declining for years. Mr. Trump has expressed a certain affection for the fuel, calling it "beautiful clean coal" to goad environmentalists, who note that coal is the dirtiest of fossil fuels and a major driver of global warming.

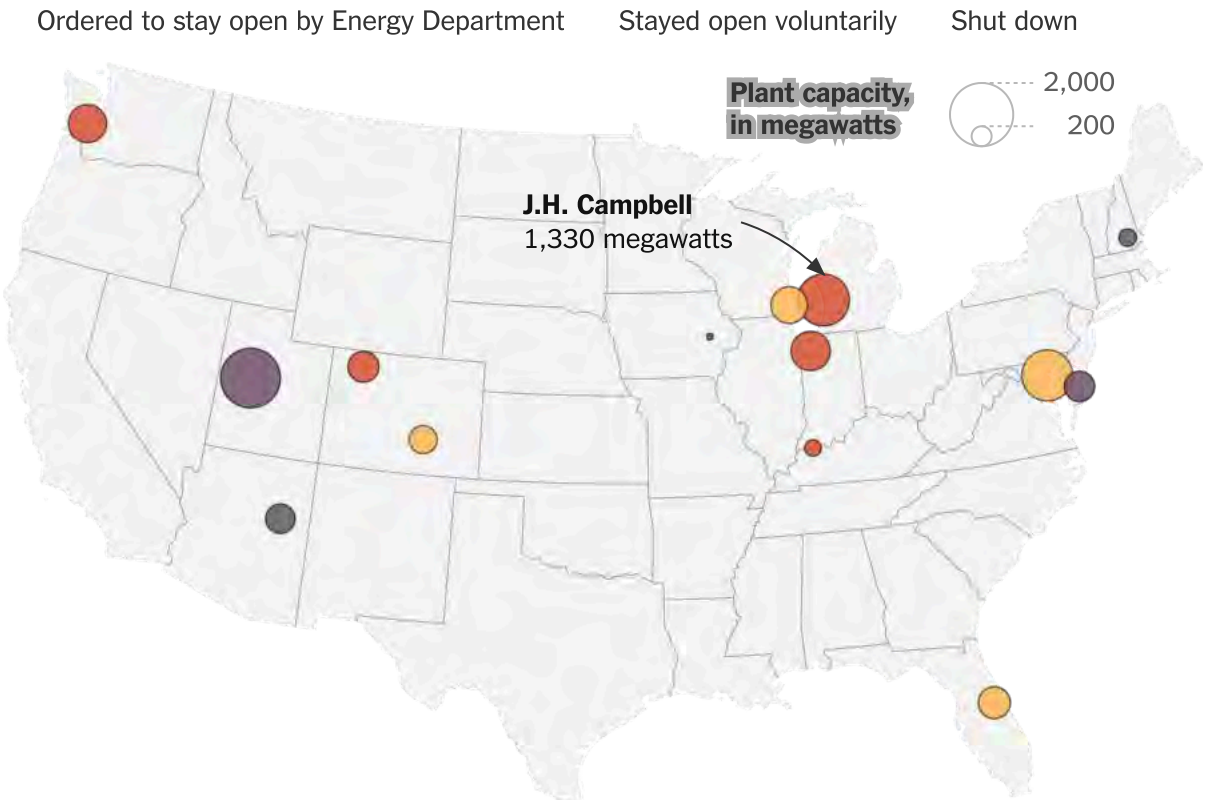
Administration officials say that keeping coal plants open is necessary to avoid blackouts and meet rising energy needs.

On the ground, however, efforts to halt coal retirements are already causing complications. Two of the coal units that the Energy Department ordered to stay online in December are broken, and it's unclear when they might be repaired.

Some plants that were ordered to keep running had already shuttered their coal mines and stopped maintaining old equipment. Now, utilities and operators are straining to revive them. The costs of extending coal-burning plants are significant, and federal and state regulators are embroiled in disputes over who will ultimately pay.

"These are old plants, and they are expensive to refurbish and keep open," said Ari Peskoe, director of Harvard Law School's Electricity Law Initiative. "The costs are going to fall on somebody. The question is whether it's the plant owners or the public."

Most coal units expected to close in 2025 were kept open



Source: U.S. Energy Information Administration. Brad Plumer/The New York Times

The debate over whether to keep aging coal plants open comes amid an astonishing turnaround in the coal industry's political fortunes.

Since 2005, the number of operating coal plants in the United States had been declining precipitously as utilities switched to cheaper and cleaner natural gas, wind and solar power. Even Mr. Trump in his first term couldn't stop the slide; more than 150 coal-burning units shut down between 2017 and 2020.

This time around, the Trump administration has gone much further to rescue coal, with more success. Last year, the amount of electricity produced by coal increased 13 percent, and retirements have slowed.

The administration has been aided by a surge in electricity demand nationwide driven by a boom in data centers, which has led some utilities to postpone coal plant closures. Federal agencies have also rolled back environmental regulations on coal, which produces more air pollution than other sources like natural gas. Burning coal also emits mercury, a powerful neurotoxin, and other heavy metals.

A surge in electricity demand has been driven by a boom in data centers. Scott Ball for The New York Times

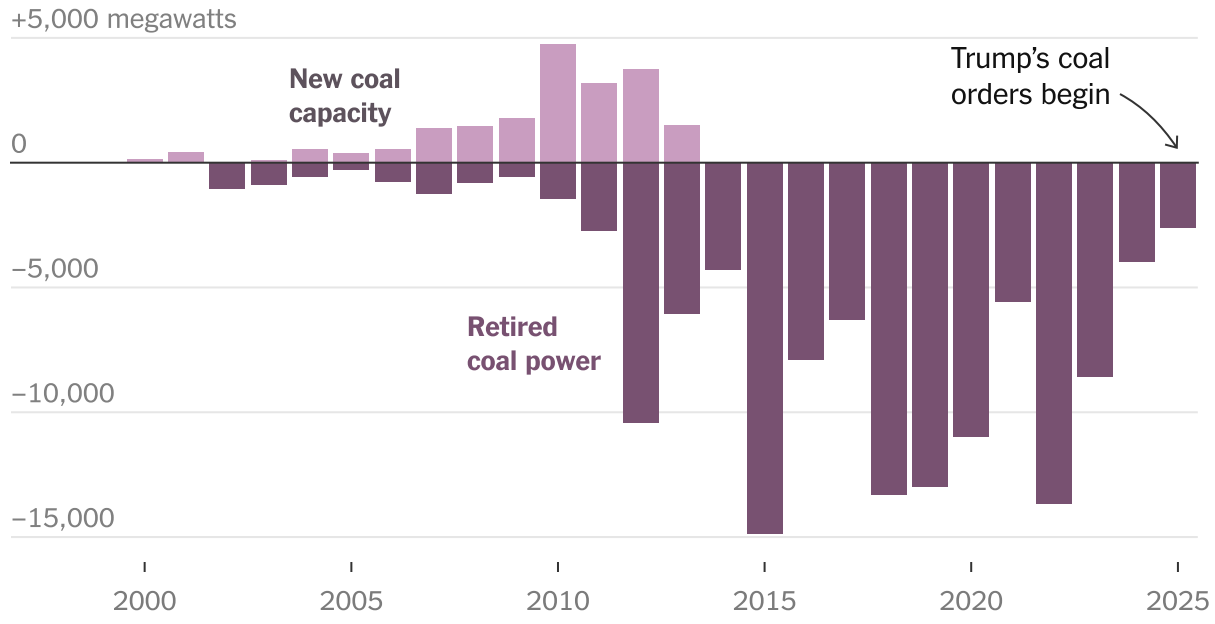
Even more drastic, however, has been the Energy Department's use of emergency orders to mandate that coal plants that had been set to retire keep operating, as the agency has invoked Section 202(c) of the Federal Power Act.

Historically, this provision has been used to keep plants online during temporary emergencies such as hurricanes or heat waves. But the Trump administration has claimed that the emergency this time is an expected shortage of reliable power over the next decade, and officials are trying to avert as many closures as they can.

The impact is already visible: At the start of last year, utilities were expected to close roughly 8.5 gigawatts of coal capacity in 2025, according to federal data. But they ended up retiring only 2.7 gigawatts, the lowest amount since 2011.

Coal retirements slowed in 2025

Changes in annual U.S. coal power capacity



Source: Energy Information Administration. Brad Plumer/The New York Times

At the White House event on Thursday, Mr. Wright said that many states were closing their coal plants for environmental reasons and that the administration would do everything it could to stop that. More than 20 gigawatts of coal capacity is currently scheduled to retire by 2028.

“I think you will not see those plants close during this administration,” Mr. Wright said, adding that there might be a few exceptions for the very oldest plants.

Mr. Wright said he hoped other actions by the administration to support coal would eventually make emergency orders “unnecessary.” But, he claimed, many utilities were quietly welcoming the orders to save coal plants at imminent risk of closure. “We get a lot of inbound calls now saying, ‘Can you 202(c) this plant?’”

Those orders are also facing a backlash. Environmental groups and states like Michigan and Washington are mounting legal challenges. The grid operator in the Midwest and state officials in Colorado have said their regions already have adequate electrical capacity, even with coal retirements.

Mr. Wright, second from the right, said that many states were closing their coal plants for environmental reasons and that the administration would do everything it could to stop that. Tierney L. Cross/The New York Times

Even analysts who agree that the country needs more power plants that can run at all hours say that forcing aging coal units to stay online can be counterproductive, because they can distort energy markets and make it harder for states and companies to plan to bring new power plants online.

“Using a blunt instrument like this to keep the legacy coal fleet online could backfire,” said Devin Hartman, director of energy and environmental policy at the R Street Institute. “There are a ton of risks.”

Broken plants, busy railroads

Reviving a geriatric coal fleet isn’t easy: Many plants are more than 50 years old and need major repairs.

On the shores of Lake Michigan, the J.H. Campbell coal plant was set to retire last May under a plan backed by the state and the electric utility that operates it, Consumers Energy. But, at the last minute, the Energy Department ordered that the plant's three coal units stay open for 90 days during the summer. The agency has since twice renewed the order and is widely expected to order that the plant remain open indefinitely.

That created headaches for the operator, which had canceled roughly $161 million in maintenance for the plant in the years leading up to the scheduled retirement, according to one engineer's testimony. The plant has struggled to generate reliable power: One unit faced extended outages in June and produced electricity for only a handful of days, according to legal filings by environmental groups.

Other plants may be in rougher shape.

In December, the Energy Department ordered that the R.M. Schahfer plant in northern Indiana keep two coal units operating past their planned retirement. Yet one of those units has been offline since the summer because of a turbine failure.

Repairing the unit could ultimately take "six months or longer," Vince Parisi, the chief operating officer of the Northern Indiana Public Service Company, which owns the plant, told regulators last month. "It's just the reality of that unit being close to retirement."

In Colorado, a rural electric cooperative had been planning since 2016 to close a coal-burning unit at the Craig Generating Station. Last month, the Energy Department ordered that the unit stay open. Yet the coal unit is offline because of a broken valve, and it is unclear how long it will take to fix it.

There's also the question of where to get fuel.

Until recently, the Craig unit in Colorado obtained some of its coal from a local mine operated by its part owner, the Tri-State Generation and Transmission Association. But that mine closed last year, laying off all its workers.

“This makes no economic sense or functional sense, to extend the life of an effectively broken coal plant,” said Gov. Jared Polis, Democrat of Colorado, who opposes the order and says the federal government had done little to consult with the state.

Last month, when Bob Guenther drove past the coal-burning power plant in Centralia, Wash., where he worked for 34 years before retirement, there wasn’t much coal in sight. The power plant had been winding down for years and was scheduled to close by Dec. 31 until the Energy Department ordered that it stay open. Coal piles that once filled acres had dwindled.

“It’s going to cost a lot of money to put that plant back in shape,” Mr. Guenther said.

The coal-burning power plant in Centralia, Wash. Reviving a geriatric coal fleet isn’t easy. Evan McGlinn for The New York Times

Some local officials and unions have cheered the lifeline for coal plants, which are often an engine of local economic activity. But environmental groups have pointed to the hazards from air pollution and coal-ash waste.

“Northwest Indiana has long borne the brunt of industrial pollution,” said Ashley Williams, the executive director of Just Transition Northwest Indiana, a nonprofit group, criticizing the order to keep the R.M. Schahfer plant open. “We will continue to suffer.”

Mounting costs, legal threats

The cost to keep coal plants open could prove especially divisive.

In Michigan, Consumers Energy spent $164 million from May to September to keep its coal plant running, according to regulatory filings. During that time, the plant earned only $84 million in revenue.

It remains to be seen who will ultimately pay for the rest. Consumers Energy has proposed that the costs be shared by ratepayers in multiple states in the Midwestern regional grid, rather than paid for by its customers alone. But other groups have challenged this proposal.

In Colorado, Tri-State has said that its ratepayers may have to bear the full cost of repairing and operating the Craig plant — which state officials say could cost $80 million per year or more. In Washington, state law now forbids utilities to buy electricity from coal plants, raising legal complications.

Preventing the nation’s coal plants from retiring over the next three years could cost consumers at least $3 billion per year, according to a report from Grid Strategies, a consulting firm.

“A lot of these plants were retiring because they’re no longer economic to operate,” said Michael Goggin, an executive vice president at Grid Strategies. “It’s expensive to keep them going.”

Opponents have challenged the coal orders in court, arguing that Congress intended for emergency powers to be used only in rare, temporary cases. If the orders are struck down, it is unclear who would bear the cost of spending millions of dollars to repair run-down plants.

While federal forecasts still expect coal generation to decline next year, the Trump administration is trying to prevent that from occurring.

The Environmental Protection Agency is rolling back numerous air pollution and climate rules that have made coal plants more costly to operate. It has also given electric utilities more time to clean up contamination from toxic coal ash landfills.

At the same time, the Energy Department has offered up to $350 million to try to bring back to life coal plants that have already closed.

Michelle Bloodworth, chief executive of America's Power, a coal trade group, estimates that at least 29 coal units with roughly 13 gigawatts of capacity have recently closed but are not yet demolished and could be candidates for restarting. She added that more utilities were voluntarily postponing coal retirements and that the future for the industry is looking brighter under the Trump administration.

"There's a huge opportunity for the coal fleet," Ms. Bloodworth said. "It's a big change after years and years of punitive environmental regulations."

Claire Brown covers climate change for The Times and writes for the Climate Forward newsletter.

Brad Plumer is a Times reporter who covers technology and policy efforts to address global warming.

A version of this article appears in print on , Section A, Page 1 of the New York edition with the headline: Trump Pushes To Retain Coal On Power Grid

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit JJJ: Harder, A., Exclusive: Wind projects pile up as Pentagon reviews stall (Mar. 30, 2026)



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Mar 30, 2026 - Energy & Climate

Exclusive: Wind projects pile up as Pentagon reviews stall



Amy Harder

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Photo illustration: Maura Losch/Axios. Photo: Win McNamee/Getty Images

More than two dozen wind farms across the U.S. are being delayed as the Trump administration sits on military reviews that were once considered routine.

Why it matters: The delays are dragging down a race led by tech companies — and backed by President Trump — to build power-hungry data centers to lead the global AI race.

By the numbers: At least 30 onshore wind farms projects are affected by the Pentagon paperwork logjam, according to Jason Grumet, head of the American Clean Power Association.

- At roughly 200 to 300 megawatts each, that's about 7.5 gigawatts of stalled capacity.

- Even accounting for the variability of wind, those farms could produce enough electricity to power several cities — or multiple large data centers.

The reviews are necessary to make sure the wind farms' turbines won't interfere with military radar or aviation systems.

What they're saying: "It is quite astounding that in the midst of this discussion about making the permitting system and governing system more efficient, we just have direct obstruction," Grumet told Axios in an interview.

- Grumet's comments, on the sidelines of the CERAWeek conference last week as part of an upcoming episode of the Shocked podcast, represent his first public remarks on the matter.

How it works: The clearance processes are usually routine, and the Pentagon negotiates any fixes that need to be made.

- It's the so-called "mitigation agreements" that are suddenly piling up unsigned in the last several months.

The big picture: Trump has long shown disdain for renewable energy, especially wind energy — and even more specifically — offshore.

- He has moved to slow the renewable energy buildout in numerous ways, including revoking leases and stalling federal permits across the federal government.

- At the same time, virtually all energy developers — alongside the Trump administration — say they want a permitting overhaul to expedite such reviews.

Flashback: Even for his style, Trump has been remarkably transparent: "My goal is to not let any windmill be built," he said at a White House meeting earlier this year. "They're losers."

The intrigue: In lawsuits over the president's efforts to kneecap offshore wind projects, the administration has cited national

asserting new, and what Grumet describes as similarly unproven, national security concerns over land-based wind.

Between the lines: The administration's position on wind energy is uneven, though.

- Last week, the Interior Department announced a rare agreement with TotalEnergies, a French energy company, to cancel its offshore wind leases totaling $1 billion and repurpose that money toward oil and gas projects.



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- Interior Secretary Doug Burgum, who oversaw wind power growth as North Dakota governor, told Axios at last week's CERAWeek conference in Houston that onshore wind is more affordable and has fewer national security concerns.

- "North Dakota is not an attack vector," Burgum said when asked to explain his shifting position. "Being literally in the center of North America is not a spot where we have to worry about drone attacks or submarine attacks coming."

The other side: The Pentagon and the White House didn't respond to requests for comment by press time.

- Sen. Martin Heinrich (D-N.M.), the top Democrat on the Senate Energy Committee, accused Trump of causing high energy prices with the Iran war and criticized the Pentagon delays.

- "If he was serious about lowering energy costs, he should stop stalling permits and start supporting made-in-America clean energy solutions," Heinrich said in a statement to Axios.

Reality check: The odds Congress will pass permitting reform this year are now 25%, down from 30%, based on an analysis updated Thursday by consulting firm Rapidan Energy Group.

What's next: In its letter to the Pentagon, the renewable energy trade group hints it could sue under federal administrative law if it doesn't hear back by April 8.

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit KKK: Department, Order No. 2026-26-31 (June 26, 2026)

Department of Energy
Washington, DC 20585

Tri-State Generation and Transmission Association,
Platte River Power Authority, Salt River Project,
PacifiCorp, and Public Service Company of Colorado, and
Southwest Power Pool
Regarding Craig Station

Order No. 202-26-31

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC)–Rocky Mountain[3] assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

Craig Station (Craig) is an electric generating facility in Craig, Colorado. Craig is operated by the Tri-State Generation and Transmission Association (Tri-State). Craig consists of three coal-fired generation units, Unit 1 (446.4 MW), Unit 2 (446.4 MW), and Unit 3 (534.8 MW), with a combined name plate capacity of 1427.6 MW.[4] Unit 1 and Unit 2 are co-owned by Tri-State, Platte River Power Authority, Salt River Project, PacifiCorp, and Public Service Company of Colorado (a subsidiary of Xcel Energy), hereinafter collectively referred to as the co-owners.[5] Unit 3 is wholly owned by Tri-State. Unit 1 and Unit 2 began operations in 1980 and 1979, respectively. Unit 3 began operations in 1984. Unit 1 was slated to cease operations in December 2025. Unit 2 and Unit 3 are slated to retire in 2028.[6]

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] The 2024 Long-Term Reliability Assessment (LTRA) from the North American Electric Reliability Corporation (NERC) included Colorado in the WECC–Northwest assessment area. The 2025 LTRA provides new assessment area boundaries for WECC to provide more geographic detail of reliability risk information and to, "reflect a more accurate alignment with operational and planning realities, as well as the footprints of various entities." In the 2025 LTRA, Colorado is included in the WECC–Rocky Mountain assessment region.

[4] U.S. Energy Info. Admin., *Form EIA-860, Schedule 3: Generator Data* (2024), https://www.eia.gov/electricity/data/eia860/.

[5] Platte River Power Authority, Craig Units 1 & 2 (Yampa Project), https://prpa.org/generation/yampa-project/.

[6] It likely would be difficult for the coal-fired unit to resume operations once retired. Specifically, practical issues, such as acquiring employment, contracts, and

Order Nos. 202-25-14 and 202-26-21, issued pursuant to FPA section 202(c) on December 30, 2025, and March 30, 2026, respectively, each required that Craig Unit 1 continue to be available to operate for 90 days, until March 30, 2026, and June 28, 2026, respectively. Those orders were based on my determination that emergency conditions existed within the WECC–Northwest and WECC–Rocky Mountain assessment areas.

Specifically, I determined that the WECC–Northwest and, later, WECC–Rocky Mountain, assessment areas faced significant amount of retiring baseload generation resources and concerns meeting demand during shoulder periods.[7] I determined that the continued operation of Craig Unit 1 would provide additional generation capacity, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.[8] I determined that the continued operation of Craig Unit 1 was necessary to alleviate immediate and anticipated threats to reliability.[9]

My determination was based on several facts. First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that in the WECC–Northwest assessment area, which included Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming, "[e]nergy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio." The 2024 LTRA notes that:

> Five [gigawatts (GW)] of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and [battery energy storage systems], further increasing variability in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of [battery energy storage systems]

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permits, may greatly increase the timeline for resumption of operations, such that the facility may not be available in the period needed. Moreover, if the co-owners were to begin disassembling the unit or other related facilities, the associated challenges would be greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick et al., *Bus. Models for Coal Plant Decommissioning*, at 9–12 (Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

[7] *See, e.g.*, *Tri-State Generation & Transmission Ass'n*, DOE Order No. 202-25-14, at 1–2 (Dec. 30, 2025) (*Tri-State*).

[8] *See id.* at 1–3.

[9] *See id.* at 3.

resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high.[10]

Second, the 2024 WECC Western Assessment of Resource Adequacy notes that peak demand in WECC's Northwest-Central subregion, which included Colorado at the time, is "forecast to grow by 8.5% over the next decade, from 33 GW in 2025 to 36 GW in 2034."[11] Meanwhile, WECC notes that most planned retirements are "baseload generation, such as coal, natural gas, and nuclear."[12]

Further, in January 2026, NERC released its 2025 Long-Term Reliability Assessment.[13] While NERC assessed that the WECC–Rocky Mountain region, which includes Colorado, is at normal risk of energy shortfalls over the next five years,[14] the area has an "[anticipated reserve margin] that falls below the [Reference Margin Level] in Summer 2034 and 2035, and Winter 2034–35."[15] The LTRA also notes that the WECC–Rocky Mountain assessment area faces challenges from an aging thermal resource fleet, which can lead to unplanned outages, exacerbated by supply chain issues, and vendor availability.[16] Additionally, both solar and wind variability are year-round concerns, and while the region is pursuing advancement into Regional Transmission Organizations (RTO) to leverage a wider footprint, smaller entities currently have limited geographic diversity to counteract these generation constraints.[17]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-14 and 202-26-21 continue, both in the near and long term.[18] The production of electricity from Craig Unit 1 continues to be critical to maintain reliability in the WECC–Rocky Mountain assessment area.

The 2025 WECC Western Assessment of Resource Adequacy notes that "the West's planned resource buildout will not keep up with anticipated load growth over the

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[10] N. Am. Elec. Reliability Corp., *2024 Long-Term Reliability Assessment*, at 13 (Dec. 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[11] WECC, *W. Assessment of Res. Adequacy 2024: Peak Demand by Subregion*, at 2, https://www.wecc.org/wecc-document/17066.

[12] WECC, *W. Assessment of Res. Adequacy 2024* , https://feature.wecc.org/wara/.

[13] NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[14] *See id.* at 7.

[15] *Id.* at 160–61.

[16] *See id.* at 161.

[17] *Id.*

[18] Further, as noted in *Tri-State*, as a coal-fired facility, it would be difficult for Craig Unit 1 to resume operations once it has been retired. *See Tri-State*, DOE Order No. 202-25-14 at 1.

next decade, particularly in the Basin and Northwest subregions. The West could see energy shortfalls as early as 2028."[19] The assessment goes on to say that "[i]f resources are added as planned, loss of load may be limited to the Basin and Northwest subregions. However, if planned resource additions are delayed or cancelled, other subregions could also be at risk."[20] Further, the assessment highlights that 90% of planned resources over the next decade are inverter-based resources, which "continue the rapid evolution of the resource mix away from traditional dispatchable resources to more weather-dependent resources."[21] The assessment notes that "entities plan to retire 22 GW of generation over the next 10 years. The vast majority is baseload generation such as coal (7 GW), natural gas (8 GW), and nuclear (2.3 GW, Diablo Canyon's two units, in 2029 and 2030)."[22]

Between 2019 and 2024, the retirement of coal-fired generating capacity in Colorado has led to a decline in the share of coal-generated electricity from 45% to 25%.[23] Looking forward, by 2029, about 3,700 megawatts (MW) of coal-fired generating capacity in Colorado is scheduled to retire according to the Energy Information Administration,[24] accounting for all but one coal-fired power plant in Colorado. In that same time frame, 620 MW of natural gas-fired generating capacity in Colorado will retire as well.[25] In 2025, intermittent wind accounted for over 5,300 MW of Colorado's electricity generating capacity.[26] Additionally, Colorado Public Utilities Commissioners have expressed concerns about the ability of certain utilities to meet projected summer 2026 loads.[27]

Finally, in May 2026, NERC released its 2026 Summer Reliability Assessment. According to NERC, Anticipated Reserve Margins will remain above the Reference Margin Level, they note that "wildfires in the region, along with extreme heat conditions

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[19] WECC, *W. Assessment of Res. Adequacy* (2025), https://feature.wecc.org/2025wara/index.html.

[20] *Id.*

[21] *Id.*

[22] *Id.*

[23] U.S. Energy Info. Admin. (EIA), *Elec. Data Browser, Net Generation for All Sectors Annually from 2019-2025, State: Colorado*, https://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vtvp&geo=0000000000g&sec=g&freq=A&start=2019&end=2024&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0.

[24] EIA, *Preliminary Monthly Elec. Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)* (Jan. 2026), https://www.eia.gov/electricity/data/eia860m/ (choose "January 2026" XLS document under "2026" column, titled "Inventory of Operating Generators as of Jan. 2026").

[25] *Id.*

[26] *Id.*

[27] *Comanche 3 Repair Delay Raises RA Concerns in Colo.*, RTO INSIDER (Mar. 26, 2026), https://www.rtoinsider.com/129021-comanche-3-repair-delay-raises-ra-concerns-in-colorado/.

for the summer, pose the greatest reliability risk scenario for the Rocky Mountains . . . [which] can impact rural communities disproportionately."[28]

Order Nos. 202-25-14 and 202-26-21 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[29] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[30] In the subsequent Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[31]

In addition, President Trump issued a White House Memo for the Secretary of Energy that emphasized the findings of Executive Order No. 14156, stating that "ensuring reliable coal supply chains and baseload power generation capacity is essential to the United States national defense… Without sufficient coal-fired baseload power, the United States will lack the stable electricity required to support defense installations, industrial expansion, and the high-energy demands of emerging technologies, such as artificial intelligence."[32] The President "further determine[d] that action to expand coal supply chain capacity and baseload generation availability is necessary to avert an

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[28] NERC, *2026 Summer Reliability Assessment*, at 37, https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[29] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/ (*Declaring a National Energy Emergency*).

[30] *Id.*

[31] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/ (*Strengthening the Reliability and Security of the United States Electric Grid*).

[32] Memorandum from President Donald J. Trump to the Secretary of Energy (Apr. 20, 2026) ("Presidential Determination Pursuant to Section 303 of the Defense Production Act of 1950, as Amended, on Coal Supply Chains and Baseload Power Generation Capacity"), https://www.whitehouse.gov/presidential-actions/2026/04/presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-coal-supply-chains-and-baseload-power-generation-capacity/.

industrial resource or critical technology item shortfall that would severely impair national defense capability."[33]

Further, the Department of Energy detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order No. 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[34]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[35] This statutory language constitutes a specific grant of authority to the Secretary to require the operation of Craig Unit 1 when the Secretary has determined that such operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity, or a shortage of electric energy or facilities for generation or transmission of electric energy.

As described above, the emergency conditions resulting from increasing demand and shortage from premature retirement of the generation facility will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Craig Unit 1 shall be made available for operation through September 26, 2026.

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[33] *Id.*

[34] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U. S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-11/DOE%20Final%20EO%20Report%20%28REVISED%20OCT%2027%29.pdf.

[35] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

Based on my determination of an emergency set forth above, I hereby order:

A. From June 29, 2026, at the direction of the Southwest Power Pool (SPP) in its role as Balancing Authority and Reliability Coordinator, Tri-State and the co-owners shall take all measures necessary to ensure that Craig Unit 1 is available to operate. For the duration of this Order, SPP is directed to take every step to employ economic dispatch of Craig Unit 1 to minimize costs to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Tri-State and the co-owners are directed to comply with all orders from SPP related to the availability and dispatch of Craig Unit 1.

B. To minimize adverse environmental impacts, this Order limits operation of Craig Unit 1 to the times and within the parameters established in paragraph A. Tri-State shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Craig Unit 1 has operated in compliance with this Order.

C. All operations of Craig Unit 1 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees, or purchase offsets or allowances for emissions that occur during the emergency conditions, or to use other geographic or temporal flexibilities available to generators.

D. By July 14, 2026, Tri-State, in coordination with the co-owners, are directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Craig Unit 1 consistent with this Order. SPP, Tri-State and the co-owners shall also provide such additional information regarding the environmental and operational impacts of this Order and its compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

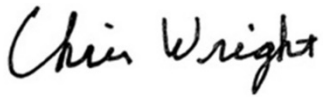
E. Tri-State and the co-owners are directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Craig Unit 1 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Craig Unit 1 shall not be considered a capacity resource.

H. This Order shall be effective from June 29, 2026, through September 26, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 26th day of June 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Colorado Public Utilities Commission
Chairman Eric Blank
Commissioner Megan Gilman
Commissioner Tom Plant

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit LLL: State of Colorado, The State of Colorado's Request for Rehearing, Motion to Intervene, and Stay Request (Apr. 28, 2026)

UNITED STATES OF AMERICA

BEFORE THE

UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-21

The State Of Colorado's Request for Rehearing, Motion to Intervene, and Stay Request

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I. Introduction

On March 30, 2026, the Department of Energy ("Department") issued Order No. 202-26-21 ("Renewed Order")[1] pursuant to its emergency authority under Section 202(c) of the Federal Power Act ("FPA")[2] ("Section 202(c)") to continue to prevent the scheduled retirement of a coal-fired generating unit at the Craig Power Station in Moffat County, Colorado. The Renewed Order requires the availability of one coal-fired unit ("Craig Unit 1") from March 31, 2026, through June 28, 2026, thereby extending for 90 days the effect of Order No. 202-25-14 ("Original Order"),[3] which was issued on December 30, 2025. After issuing the Original Order, the Department denied all prior Requests for Rehearing with no analysis or reasoning and has made no attempt to seek comment or advice as to whether a continued extension is necessary or whether there are alternative solutions to its perceived emergency.

There is still no emergency justifying the Department's Renewed Order, and even if there were, preventing the retirement of Craig Unit 1 is not the best (or even a reasonable) way to meet the alleged emergency, and does not serve the public interest. Therefore, this Renewed Order, like the Department's Original Order to prevent the retirement of Craig Unit 1, is illegal. The FPA limits the use of Section 202(c) to addressing specific, imminent capacity shortfalls resulting from unexpected outages, natural disasters, extreme weather, and similar circumstances. Here, the Department has declared an emergency due to "a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes" in the

[1] Exhibit TT (Department, Order No. 202-26-21 (March 30, 2026)).
[2] 16 U.S.C. § 824a(c).
[3] Exhibit A (Department, Order No, 202-25-14 (Dec. 30, 2025)).

Western Electricity Coordinating Council ("WECC") Rocky Mountain assessment area.[4] But, like the Original Order, the Renewed Order's emergency determination cannot stand against even the mildest scrutiny.

As Colorado demonstrated in its first Request for Rehearing, Motion to Intervene, and Stay Request ("Original Request")[5] of the Original Order, there is no energy "emergency" as defined by Section 202(c) in the WECC-Rocky Mountain assessment area or in Colorado. Rather, the Unit's owners and their respective state utility commissions have been planning for Craig Unit 1's retirement for the last decade.[6] These comprehensive planning processes have ensured that there are reliable and affordable resources available to meet the energy needs in the areas served by Craig Unit 1, such that its long-planned retirement does not create an emergency.

The Department's illegal use of its Section 202(c) authority to require the continued availability of Craig Unit 1 for an additional 90 days, unsupported by any evidence of an imminent energy emergency, will result in unnecessary operational and maintenance costs that will be imposed on ratepayers in Colorado, including the State of Colorado as a utility customer, and potentially other states. Continued operation of Craig Unit 1 pursuant to the Renewed Order will also emit needless pollution into Colorado and its neighboring states, which the Department failed to

[4] Exhibit TT. This is a change from the Original Order, which declared an energy emergency in the WECC-Northwest assessment area. Exhibit A.
[5] Exhibit CCC (State of Colorado, The State of Colorado's Request for Rehearing, Motion to Intervene, and Stay Request (Jan. 28, 2026)).
[6] *See, e.g.,* Exhibit C (Declaration of Erin O'Neil (Apr. 28, 2026)), ¶ 33.

meaningfully consider or address, as it was required to do. The Renewed Order, like the Original Order, illegally intrudes on the authority of the states to ensure the resource adequacy of their electric grids and to dictate energy policy within their borders, and improperly attempts to impose the administration's policy preferences on state ratepayers.

Pursuant to Section 313*J* of the FPA,[7] the Colorado Attorney General, on behalf of the State of Colorado, timely submits this Request for Rehearing, Motion to Intervene, and Stay Request ("Request") seeking rehearing of the Renewed Order. The Department should grant rehearing and rescind the Renewed Order because it is an unlawful abuse of the Department's emergency authority, is unsupported by evidence showing a true emergency, and is arbitrary and capricious.

II. Motion To Intervene

The State of Colorado moves to intervene in the proceeding initiated by the Renewed Order and become a party for purposes of Section 313*J* of the FPA.[8] The State of Colorado is aggrieved by the Renewed Order in several ways.

First, households and businesses in Colorado have and will be required to pay higher electricity bills because of the Renewed Order.[9] Through a carefully planned process driven by economic considerations, the owners of Craig Unit 1 planned to

[7] 16 U.S.C. § 825*l*.
[8] *Id.*
[9] Exhibit D (Declaration of Joseph Pereira (Apr. 24, 2026)). Because the Order directs the Craig Unit 1 Owners to seek cost recovery the possibility of increased rates is a foreseeable harm for Colorado. Exhibit A, ¶ E. Tri-State and PRPA have confirmed that their "members and customers must pay" the costs of DOE's Original Order. However, Colorado reserves all rights to dispute that costs incurred based on the Order are appropriate.

retire the Unit and replace it with more cost-effective facilities.[10] By ordering the continued operation of Craig Unit 1, the Renewed Order guarantees that Tri-State Generation and Transmission Association, Inc. ("Tri-State"), PacifiCorp, Platte River Power Authority ("PRPA"), Salt River Project, and Public Service Company of Colorado ("Public Service") (together, "Craig Unit 1 Owners"), will incur higher costs to serve their members and customers, which they will then likely seek to pass on to their electricity consumers, including rural customers in Colorado.[11] Tri-State has already had to pass the cost of repairing Craig Unit 1 on to its customers,[12] which include the State.

Second, the Craig Unit 1 Owners determined that it is prudent to retire Craig Unit 1 and replace it with more reliable and cost-effective resources. And the Colorado Public Utilities Commission ("CoPUC") determined that retiring Craig Unit 1 will not affect Tri-State's resource adequacy.[13] By continuing to delay the retirement of a 45-year-old coal-fired unit, the Department is causing Colorado's electric customers to be served by a more costly and less reliable and resilient electric grid. Instead of continuing to invest in and develop more reliable resources as planned, the Craig Unit 1 Owners will have to dedicate resources to repair and maintain a coal plant that is less reliable and more costly than other generation resources. For

[10] Tri-State, *Reliable, Lowest-Cost, Reduced Emissions Preferred Portfolio Focus of Tri-State Resource Plan Filing* (Apr. 11, 2025) (last visited Apr. 24, 2026).
[11] Exhibit D, ¶¶ 10, 16.
[12] Exhibit UU (Tri-State, *Request for Clarification and for Rehearing of Tri-State Generation and Transmission Association and Platte River Power Authority* (Jan. 29, 2026)).
[13] *See e.g.*, Exhibit E (CoPUC, Decision No. C25-0612, issued on August 26, 2025, in Proceeding No. 23A-0585E), at ¶ 116; CoPUC, Decision No. R22-0191, issued on March 28, 2022, in Proceeding No. 20A-0528E.

example, due to limited transmission capacity, Craig Unit 1's continued operation will prevent the use of solar electricity generated by its new solar farm in Moffat County.[14]

Third, Colorado will suffer environmental harms from Craig Unit 1's operation pursuant to the Renewed Order. Craig Unit 1 is a significant source of particulate matter ("PM"), nitrogen oxides ("NOx"), sulfur dioxide ("SOx"), carbon monoxide ("CO"), mercury, hazardous air pollutants ("HAPs"), and greenhouse gas ("GHG") emissions, and its scheduled retirement would have resulted in significant emissions reductions.[15] Operating Craig Unit 1 beyond its planned retirement date will increase the amount of pollution emitted in Colorado, harming the environment, public health, and welfare, as well as Colorado's ability to comply with other federal and State environmental laws.[16] The Renewed Order does not make a meaningful attempt to minimize or mitigate the emissions impact of continued operation of Craig Unit 1 as required.

Finally, State authority over generation resources has been a bedrock principle of the FPA for nearly a century. Federal intrusion in this traditional sphere of state control is permitted only in a true emergency and only with specific procedures that the Department did not follow when issuing the Renewed Order. Colorado's sovereign interest in seeing its State laws followed in an area reserved to State sovereign authority further warrants the State's intervention.

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[14] Exhibit UU.
[15] Exhibit B (Declaration of Josh Korth (Apr. 27, 2026)), ¶¶ 14-19.
[16] *See* generally, *infra;* Exhibit B, ¶¶ 16-23.

III. Background

Like the Original Order, the Renewed Order makes several unfounded claims about Colorado's energy resource mix, expected increases in energy demand in the region, and the resulting need for continued availability of Craig Unit 1 to address an alleged energy emergency.

A. Craig Unit 1 is owned by several utilities with specific service areas.

Craig Unit 1, along with Craig Units 2 and 3, comprise Craig Station, a 1,285 megawatt ("MW"), generating facility in Moffat County, CO.[17] Craig Units 1 and 2, also known as the Yampa Project, are operated solely by Tri-State but are co-owned by Craig Unit 1 Owners. Craig Unit 1 has a 427 MW capacity and began operating in 1980, making it over 45-years-old.[18] Craig Unit 1 was approved to retire on December 31, 2025. Craig Unit 2, which has a 410 MW capacity, has an approved retirement date of September 30, 2028, and Craig Unit 3, which is solely owned and operated by Tri-State and has a 448 MW capacity, will retire by 2030.[19]

Tri-State is a wholesale electric generation and transmission cooperative association with members located across Colorado, Nebraska, New Mexico, and Wyoming. Tri-State is a non-profit corporation and is owned and governed by its

[17] Tri-State, *Craig Station Unit 2 owners announce retirement date of Sept. 30, 2028* (July 8, 2020), (last visited Jan. 26, 2026); Exhibit F (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding no. 20A-0528E, Attachment BN-2, (Tri-State, 2020 IRP/ERP, Public (Dec. 1, 2020)), at 182.
[18] Global Energy Monitor, a project of the Sierra Club, *Craig Station* (last updated Jan. 5, 2026) (last visited Jan. 26, 2026); Exhibit F, at 182.
[19] Tri-State, *Craig Station Unit 2 owners announce retirement date of Sept. 30, 2028* (July 8, 2020); Exhibit F, at 182; Exhibit G (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-1 (Tri-State, Responsible Energy Plan ("Responsible Energy Plan") (Jan. 2020)), at 3.

members through a Board of Directors.[20] Tri-State's board is responsible for approving rates, major capital investments, and resource planning decisions.[21] These resource planning decisions must then be approved by the CoPUC. Tri-State's ownership share of Craig Unit 1 is 24%, and Tri-State therefore is entitled to 102.5 MW out of Craig Unit 1's 427 MW capacity.[22] It is Colorado's understanding that within Tri-State's service territory, only Colorado and Wyoming receive energy from Craig Unit 1. PRPA and Public Service are the two other Colorado-based utilities with an ownership stake in Craig Unit 1. PRPA is a non-profit community-owned power generation and transmission utility that provides energy to Estes Park, Fort Collins, Longmont, and Loveland, Colorado.[23] PRPA has an 18% ownership share of Craig Unit 1 and is therefore entitled to 77 MW of Craig Unit 1's capacity.[24] Public Service is a subsidiary of Xcel Energy, Inc., and is the largest gas and electric provider in Colorado. However, Public Service has the smallest ownership stake in Craig Unit 1, owning 9% (38.4 MW of Craig Unit 1's total capacity).[25]

The Salt River Project and PacifiCorp are the two non-Colorado owners of Craig Unit 1. The Salt River Project is a non-profit organization that provides power in central Arizona.[26] The Salt River Project owns 29% of Craig Unit 1 (124 MW of Craig

[20] Exhibit JJ (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Proceeding 20A-0528E), at 13:8-13.
[21] *Id.*, at 13:16-22.
[22] Exhibit J (CoPUC, 120 Day ERP Implementation Report, Public, filed on April 11, 2025, in Proceeding No. 23A-0585E).
[23] Exhibit EE (PRPA, *2024 Integrated Resource Plan* (Apr. 2023)).
[24] Exhibit FF (PRPA, *Craig Units 1&2 (Yampa Project)* (2026)).
[25] Global Energy Monitor, *Craig Station*.
[26] Exhibit H (Salt River Project, *2023 Integrated Systems Plan*), at 6.

Unit 1's total capacity).[27] However, the Salt River Project did not receive energy from Craig Unit 1 directly and instead traded for it through the Western Area Power Administration ("WAPA") until April 1, 2026 when that contract expired. PacifiCorp is based in Oregon but serves customers in Oregon, Washington, California, Utah, Idaho, and Wyoming. PacifiCorp has a 19% ownership of Craig Unit 1 (81 MW of Craig Unit 1's total capacity). Neither utility's service territory is in the WECC-Rocky Mountain assessment area.

B. The Craig Unit 1 Owners decided to retire Craig Unit 1 ten years ago and included the retirement in their resource plans.

In 2016, the Craig Unit 1 Owners voluntarily decided to retire Craig Unit 1 by December 31, 2025, based on "the [S]tate and federal regulatory environment for coal-based generation, current and forecasted market conditions, the significant costs to install additional emissions controls, and the best interests of electric consumers."[28] The Craig Unit 1 Owners agreed to proposed revisions to Air Quality Control Commission ("Air Commission") Regulation No. 23 and Colorado's Regional Haze State Implementation Plan ("SIP") to include the December 31, 2025 retirement date.[29] The U.S. Environmental Protection Agency ("EPA") approved Craig Unit 1's retirement date on July 5, 2018.[30] Since 2016, the Craig Unit 1 Owners have incorporated the planned closure of the unit as an assumption in all electric resource

[27] *Id.*, at 27.
[28] Tri-State, *Craig Station Owners, Regulators and Environmental Groups Reach Agreement on Proposed Revisions to Colorado Regional Haze Plan* (Sep. 1, 2016).
[29] *See id.*; 5 Colo. Code Reg. § 1001-27, Part A, Section IV.D.1 (2025).
[30] Air Plan Partial Approval and Partial Disapproval; Colorado; Regional Haze Plan for the Second Implementation Period, 83 Fed. Reg. 31332 (July 5, 2018).

planning proceedings, reports, decisions and modeling.[31] None of these processes or reports conclude that resource adequacy or reliability would be threatened by the unit's retirement.

Tri-State's resource plans are overseen by the CoPUC. The CoPUC reviewed Tri-State's load forecasts, resource needs, and planned resource acquisitions, all of which included the retirement of Craig Unit 1 by December 31, 2025 as an underlying assumption, as part of Tri-State's 2020 ERP and most recently its 2023 ERP for planning years 2026-2031.[32] As recently as August 2025, the CoPUC found that "Craig Unit 1 is not required for reliability or resource adequacy purposes based on the record in this ERP. Every portfolio that Tri-State modeled for its most recent ERP assumes that Craig Unit 1 retires at the end of 2025. . . every portfolio meets all reliability metrics and is reliable."[33] The CoPUC further found that Tri-State's resource plan—including the retirement of Craig Unit 1—is resource diverse and cost effective, ensuring energy security, economic prosperity, and environmental protection. Tri-State reaffirmed on January 23, 2026, that the Craig Unit 1 retirement "has informed operational and maintenance decisions, and Tri-State has planned for adequate resources to maintain reliability on its system following the unit's

[31] Tri-State, *Craig Station Owners Agreement* (Sep. 1, 2016); *e.g.*, CoPUC, *Tri-State, ERP Annual Progress Report, Revised*, filed on June 2, 2017, in Proceeding No. 15M-0852E, at 16; CoPUC, ERP for Annual Progress Report, filed on October 31, 2018, in Proceeding No. 15M-0852E, at 17; CoPUC, ERP Annual Progress Report, filed on December 10, 2019, in Proceeding No. 15M-0852E, at 22.
[32] Exhibit F, at 31; CoPUC, 150-Day Report, Public, filed on February 13, 2023, in Proceeding No. 20A-0528E, at 28; Exhibit X (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 (Tri-State, 2023 ERP Phase I, Rev. 2 (Apr. 22, 2024)), at 19, 21, 32, 44, 55, 66; Exhibit J, at 21, 32, 43, 54, 64, 75.
[33] Exhibit E, ¶ 116.

retirement."[34] And the Resource Adequacy Report filed by Tri-State on March 17, 2026, did not present any resource adequacy or reliability issues, and continues to project no capacity shortfalls through 2035.[35] PRPA, which conducts its own integrated resource planning process, also has sufficient resources without Craig Unit 1. In fact, both PRPA and Tri-State challenged the Original Order because they do not need Craig Unit 1 and do not wish to unnecessarily incur costs to operate it.[36]

The other Craig Unit 1 Owners are subject to similar oversight by their state utility commissions. As part of their respective state-approved resource plans, Salt River Project and PacifiCorp have confirmed there are no resource adequacy concerns in their respective states associated with the retirement of Craig Unit 1.

Underscoring the lack of need for Craig Unit 1, the unit suffered an outage on December 19, 2025 due to a mechanical failure of a valve.[37] Absent the Original Order, it is unlikely the Owners would have expended new resources to repair the aging unit given that they were not expecting to use it to generate energy after December 31st. Tri-State and the co-owners paid for the repair of Craig Unit 1 pursuant to the Original Order, and this cost has been passed along to Tri-State's and PRPA's,[38] and likely the other utilities', customers. Craig Unit 1 was in a forced

[34] Tri-State, *Tri-State makes Craig Generating Station Unit 1 available to operate in compliance with DOE emergency order* (Jan. 23, 2026).
[35] Exhibit VV (CoPUC, Tri-State, Notice of 2026 Resource Adequacy Annual Report, filed on March 17, 2026, in Proceeding No. 26M-0028E).
[36] Exhibit UU.
[37] Exhibit QQ (Tri-State, *U.S. DOE Orders Tri-State to Keep Craig Generating Station Unit Operating for Next 90 Days* (Dec. 31, 2025)); *see also* Exhibit B, ¶ 11; Exhibit D, ¶ 15.
[38] Exhibit UU.

outage until its repairs were completed around mid-January,[39] and it was then available to operate, but did not operate, for the remainder of the period of the Original Order.

C. Federal Energy Regulatory Commission ("FERC") and its designated entities also oversee resource planning decisions for Craig Station to ensure reliability.

The structure of FERC's management of the bulk power system is important to understand various studies and reports as they relate to the claimed emergency identified in the Renewed Order. The reliability and resource adequacy of the electric power system in states that are not within Independent System Operators ("ISOs") or Regional Transmission Organizations ("RTOs") are typically managed by individual utilities, which are often vertically integrated, meaning they handle generation, transmission, and distribution of electricity within their service areas, and are typically overseen by state public utilities commissions or a similar state entity.[40] These utilities are also subject to reliability oversight by FERC and several balancing authorities, in addition to being subject to their state resource planning and reliability requirements. Utilities in an RTO, which now includes Tri-State and PRPA,[41] are subject to additional frameworks and oversight. These related processes are designed to govern long-term planning and resource adequacy, and are reserved to FERC, RTOs, and the states under the FPA.[42]

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[39] Tri-State, *Tri-State makes Craig Generating Station Unit 1 available to operate in compliance with DOE emergency order* (Jan. 23, 2026).
[40] FERC, *Energy Markets* (Aug. 18, 2025) (last visited Jan. 26, 2026).
[41] Tri-State and PRPA are part of the Southwest Power Pool ("SPP")'s RTO expansion in the Western Interconnection, which began operations on April 1, 2026.
[42] *See* 16 U.S.C. § 824(b)(1); 16 U.S.C. § 824a(b).

FERC oversees the reliability of the bulk power system, which is the network of generation, transmission, and distribution system components across the United States, by reviewing, approving, and enforcing mandatory reliability standards developed by the North American Electric Reliability Corporation ("NERC").[43] FERC designated NERC as the Electric Reliability Organization ("ERO") for the mainland United States in 2006 pursuant to the Energy Policy Act of 2005.[44] NERC is a non-profit international regulatory authority that assures the reliability of North America's bulk power system by creating reliability standards, approved by FERC, that are legally enforceable and include training and communications requirements, and emergency back up plans.[45] These standards apply to all users, owners, and operators of the continental United States' bulk power system.[46] NERC also annually analyzes seasonal and long-term reliability of the bulk power system and assesses risk by region using a three-tiered system.[47]

NERC is permitted to delegate authority to regional entities for the purpose of proposing and enforcing reliability standards.[48] NERC therefore divides the North American bulk power system into six regional entities to which it has delegated authority. One of these regional entities is WECC, which covers most of the Western

[43] FERC, *Reliability Explainer* (Aug. 16, 2023) (last visited Jan. 26, 2026).
[44] *See id.*; 16 U.S.C. § 824*o*(a)(2); N. Am. Elec. Reliab. Corp., 116 FERC ¶ 61,062 (2006), at 3, order on reh'g & compliance, 117 FERC ¶ 61,126 (2006).
[45] FERC, *Reliability Explainer* (Aug. 16, 2023).
[46] 16 U.S.C. § 824o(b)(1).
[47] *See* 18 C.F.R. § 39.11.
[48] 18 C.F.R. § 39.8.

United States, including all of the states served by Craig Unit 1.[49] WECC is a non-profit organization that assures a reliable electric system in the Western Interconnection, a region that covers the Pacific Ocean to the Rocky Mountain states.[50] All of the Craig Unit 1 Owners are members of WECC.[51]

WECC identifies and registers the Reliability Coordinators and balancing authorities that are responsible for maintaining operating conditions under NERC's reliability standards within its region.[52] Reliability Coordinators are the highest level of authority under NERC. They are responsible for the operation of the bulk electric system and have the operating tools, procedures, and authority to prevent or mitigate emergency operating situations.[53] Balancing authorities ensure that power system demand and supply are balanced, manage transfers of electricity and use economic dispatch to optimize the use of generating units and minimize real-time costs, and maintain operating conditions under NERC reliability standards.[54] As of April 1, 2026, Southwest Power Pool, Inc. ("SPP") is the Reliability Coordinator for Public Service, Tri-State, and PRPA, and the Balancing Authority for Tri-State and PRPA.[55]

[49] *See* Fully Executed North American Electric Reliability Corp., *Amended And Restated Delegation Agreement Between NAERC And WECC* (2021 FERC Revisions – Clean) (Jan. 1, 2021).
[50] EPA, *U.S. Grid Regions* (Nov. 24, 2025).
[51] WECC, *Membership* (2026).
[52] Department, *Learning Series: Energy Security & Resilience*; WECC, *Registration and Certification* (2026).
[53] NERC, *NERCipedia: Reliability Coordinator* (2024).
[54] Department, *Learning Series: Energy Security & Resilience*.
[55] SPP, *2026 RTOE SWPW Transition Plan – Market Participant* (Version 2.2, Mar. 19,2026).

In addition to this structure, FERC has encouraged the formation of nonprofit entities known as ISOs and RTOs.[56] FERC concluded that the use of ISOs and RTOs could address operational and reliability issues, improve transmission grid management, improve market performance, and facilitate lighter regulation.[57] RTOs and ISOs work with FERC and the states to ensure resource adequacy by imposing resource adequacy requirements on member utilities and monitoring the day to day operations of the grid.[58]

In December 2025, the CoPUC determined that it is in the public interest for Tri-State to join the SPP RTO as part of SPP's western expansion in April of 2026.[59] Both Tri-State and PRPA joined the SPP RTO on April 1, 2026.[60] The SPP RTO is a "nonprofit corporation mandated by [FERC] to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale electricity prices on behalf of its members."[61] The SPP RTO runs an Integrated Marketplace, which includes, among other things, a real time balancing market and a day ahead market.[62] SPP RTO's western expansion includes parts of Colorado, Wyoming, and several other states, but its footprint does not align exactly with either the WECC-Rocky Mountain region or the WECC-Basin region.[63]

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[56] Regional Transmission Organizations, 65 Fed. Reg. 810, 811 (Jan. 6, 2000); Promoting Wholesale Competition Through Open Access Non-Discriminatory Transm. Servs. by Pub. Utils. and Recovery of Stranded Costs by Pub. Utils. and Transm. Utils., 61 Fed. Reg. 21540-01, 21542 (May 10, 1996).
[57] 65 Fed. Reg. at 811.
[58] Klass A., *The President and the Power Grid*, Mich. L. Rev. Online (forthcoming Apr. 2026).
[59] CoPUC, Decision No. C25-0906, issued on December 16, 2025, in Proceeding No. 25A-0266E, ¶ 2.
[60] SPP, *Order Accepting Tariff Revisions, Subject to Condition*, 190 FERC ¶ 61,169 (Mar. 20, 2025)
[61] SPP, *About Us* (last visited Apl. 24, 2026).
[62] *Id.* at *SPP Portal*.
[63] Compare *Id*. at *RTO Expansion* to Exhibit WW (NERC, *Long-Term Reliability Assessment* (Jan. 2026).

The Renewed Order states, without support, that the WECC-Rocky Mountain Assessment area is experiencing an energy emergency based on NERC's 2025 Long-Term Reliability Assessment ("2025 LTRA"). But neither NERC, WECC and its designees, nor SPP have made a similar emergency determination. The Renewed Order cites to the 2025 LTRA's statements that the Rocky Mountain assessment area's anticipated reserve margin falls below the reference margin level for the first time in Summer 2034, that there is an aging thermal resource fleet, and that solar and wind variability are year-long concerns.[64] However, the Renewed Order itself notes that the 2025 LTRA found that the WECC-Rocky Mountain region is at a normal risk of energy shortfalls over the next five years.[65] NERC defines "normal risk" as resource adequacy criteria being met, and are expected to have sufficient resources for extreme conditions.[66] A region cannot have a better designation than "normal risk" in a LTRA. The Renewed Order also cites to the 2025 WECC Assessment's statement that the Basin and Northwest subregions planned resource buildout will not keep up with anticipated load growth over the next decade, despite the fact that the Renewed Order only declares an emergency in the Rocky Mountain subregion.[67]

Even if these reports had included credible evidence of an emergency in the Rocky Mountain assessment area, the 2025 LTRA and 2025 WECC Assessment do not address short-term, imminent reliability issues. These reports also do not account for the westward expansion of SPP's RTO and the resulting mismatch between SPP West

[64] *Id.*
[65] Exhibit TT, n. 3.
[66] Exhibit WW, at 7.
[67] Exhibit TT.

and WECC-Rocky Mountain's footprints. Therefore, these reports cannot support a decision by the Department to keep one power plant open in the name of the Department's alleged region-wide emergency.

Thus, the assessments covering the areas served by Craig Unit 1 for both the 90-day term of the Renewed Order and beyond do not conclude that there is an energy shortfall or a reliability concern. Yet, the Department has re-issued a Section 202(c) Order declaring that an emergency exists within the WECC-Rocky Mountain assessment area "due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes."[68] The Renewed Order requires the Craig Unit 1 Owners to ensure that the unit is available to operate for the next 90 days and directs SPP to employ economic dispatch of Craig Unit 1.[69]

D. The Renewed Order is part of the broader federal efforts to support the coal industry.

On January 20, 2025, President Trump issued Executive Order 14156, "Declaring a National Energy Emergency."[70] That declaration did not provide any factual support for its assertion that the country was in the grips of an electricity emergency. In fact, U.S. energy production is at an all-time high and continues to grow.[71] Although the President recently extended the energy emergency declaration

[68] Exhibit TT, at 2.
[69] *Id.*
[70] Declaring a National Energy Emergency, 90 Fed. Reg. 8433 (Jan. 20, 2025).
[71] Zaretskaya, V., *The United States was the world's largest liquified natural gas exporter in 2023* (Apr. 1, 2024); U.S. Energy Info. Admin., *U.S. Exports of Crude Oil* (Dec. 31, 2025); U.S. Energy Info. Admin., *U.S. Energy Facts Explained: Imports & Exports* (July 15, 2024).

for an additional year, he did not cite any new evidence to justify the supposed emergency.[72]

Setting the stage for the Department's plan to use Section 202(c) orders to promote the administration's policy preferences for the nation's energy mix, on April 14, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid."[73] This Executive Order directed the Department to streamline and expedite processes for issuing emergency orders under Section 202(c). It also ordered the preparation of a methodology to help identify areas with inadequate reserve margins and directed the use of Section 202(c) orders to prevent certain generation resources from leaving the bulk power system.[74] Pursuant to this Executive Order, the Department published its report titled *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* ("Resource Adequacy Report" or "Report"),[75] on July 7, 2025.

Colorado and several other states filed a request for rehearing of the Resource Adequacy Report that pointed out the Report's many analytical errors, including flawed and unexplained assumptions for load growth projections and resource retirements and additions.[76] The Department itself acknowledges in the Report that

[72] Continuation of the National Emergency With Respect to Energy, 91 Fed. Reg. 1667 (Jan. 12, 2026).
[73] Exec. Order 14262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521 (Apr. 14, 2025).
[74] *Id*.
[75] Exhibit M (Department, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (July 2025)).
[76] Exhibit N (Motion to Intervene and Protective Request for Rehearing by the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York, filed on August 6, 2025 with the Department).

the agency is not equipped to analyze resource adequacy, stating that its own analysis "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[77] Thus, despite issuing a Report intended to guide its use of Section 202(c) authority, the Department does not have the ability to discern whether there is an energy emergency at the regional level.

Nevertheless, the Department proceeded to issue numerous orders under Section 202(c) in 2025 to prevent the retirement of several fossil fuel-fired power plants across the country. In May 2025, the Department issued orders preventing two fossil-fuel generation facilities in Michigan and Pennsylvania from retiring as planned. Both orders failed to identify an imminent energy emergency justifying the units' continued operation and instead cited only generalized concerns about resource adequacy.[78] The Department has now re-issued both orders multiple times.[79]

In December 2025, four additional fossil fuel-fired generation facilities were scheduled to retire, and the Department issued orders requiring their continued availability. In addition to the Renewed Order at issue in this proceeding, the Department ordered that units in Washington and Indiana remain available to operate, and the Department has recently re-issued all three of those orders.[80] Like

[77] Exhibit M, at 2.
[78] Exhibit O (Department, Order No. 202-25-3 ("Campbell Order") (May 23, 2025)); Exhibit P (Department, Order 202-25-4 ("Eddystone Order") (May 30, 2025)).
[79] *See* Exhibit I (Department, Order No. 202-25-7 (Aug. 20, 2025") ("Aug. Campbell Extension")); Exhibit U (Department, Order No. 202-25-9 (Nov. 18, 2025) ("Nov. Campbell Extension"); Exhibit V (Department, Order No. 202-25-8 (Aug. 28, 2025) ("Aug. Eddystone Extension")); Exhibit PP (Department, Order No. 202-25-10 (Nov. 25, 2025) ("Nov. Eddystone Extension")); Exhibit XX (Department, Order No. 202-26-16 (Feb. 17, 2026)) ("Feb 2026 Campbell Extension"); Exhibit YY (Department, Order No. 202-26-17 (Feb. 23, 2026)) ("Feb 2026 Eddystone Extension").
[80] Exhibit Q (Department, Order No. 202-25-11 (Dec. 16, 2025) ("Centralia Order")); Exhibit S (Department, Order No. 202-25-12 (Dec. 23, 2025) ("Schahfer Order")); Exhibit R (Department, Order

the Renewed Order, the other Section 202(c) orders issued in December also failed to support their emergency determinations with evidence of a specific, imminent energy shortfall or other circumstances that qualify as an emergency under Section 202(c).

IV. Statement of Issues and Specifications of Error

The State of Colorado submits the following statement of issues and specifications of error:

1. The Renewed Order is contrary to law because Section 202(c) only authorizes the Department to respond to specific, imminent, unexpected, and temporary events, while the Renewed Order addresses long-term resource adequacy concerns. The statutory text, legislative history, judicial construction, and the Department's regulations all confirm that an emergency must be specific, imminent, unexpected, and temporary. 16 U.S.C. § 824a(c); *Richmond Power & Light of City of Richmond, Ind. v. FERC*, 574 F.2d 610 (D.C. Cir. 1978); S. Rep. No. 74 621, 74th Cong., 1st Sess. (1935); 16 U.S.C. § 824a(a) & (b); *Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232 (8th Cir. 1970).

2. The Renewed Order is contrary to law because it exceeds the Department's statutory authority by preventing the long-planned retirement of Craig Unit 1. Section 201(b) of the FPA reserves decisions about plant retirement dates to the states, and Section 202(c) does not vest the Department with general regulatory authority over resource adequacy. By abusing a statute meant only for emergencies, the Renewed Order intrudes on authority reserved to states and to other federal regulators to regulate resource adequacy. 16 U.S.C. §824(a); *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009); *see also Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 155 (2016); *Devon Power LLC et al.*, 109 FERC ¶ 61,154, P 47 (2004).

3. The Renewed Order is contrary to law because it fails to present substantial evidence for its emergency determination and ignores critical facts. None of the materials cited in the Renewed Order provide evidence of an emergency in the WECC-Rocky Mountain assessment area, and the Renewed Order ignores critical facts, including the findings in its

No. 202-25-13 (Dec. 23, 2025) ("Culley Order")); Exhibit ZZ (Department, Order No. 202-26-18 (Mar. 16, 2026)) ("March 2026 Centralia Extension"); Exhibit AAA (Department, Order No. 202-26-19 (Mar. 23, 2026)) ("March 2026 Schahfer Extension"); Exhibit BBB (Department, Order No. 202-26-19 (Mar. 23, 2026)) ("March 2026 Culley Extension").

own Resource Adequacy Report, NERC's findings, and State and utility analyses. *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983); *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962); *Chritton v. National Transportation Safety Board*, 888 F.2d 854, 856 (D.C. App. 1989); *Richmond Power & Light of City of Richmond, Ind. v. FERC*, 574 F.2d 610 (D.C. Cir. 1978); S. Rep. No. 74-621 (1935); 16 U.S.C. § 824a(a) & (b); *Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232 (8th Cir. 1970); *Emera Maine v. FERC*, 854 F.3d 9, 22 (D.C. Cir. 2017); *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

4. The Renewed Order is arbitrary and capricious because it requires generation that does not best meet the claimed emergency. 16 U.S.C. § 824a(c)(1); *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208 (2009); *Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1 (2020); *Motor Vehicle Mfrs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983); 10 C.F.R. § 205.371.

5. The Renewed Order's terms fail to comply with Sections 202(c)(2) and 202(c)(4)(b) of the FPA, and Section 103(b) of the Department Organization Act. 16 USC § 824a(c)(1); 16 U.S.C. § 824a(c)(2); 42 U.S.C. § 7113; *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009); *see also, e.g., Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 155 (2016).

6. The Renewed Order is arbitrary and capricious because it is designed to support the federal administration's policy goal of supporting the coal industry. *Dep't of Commerce v. New York*, 588 U.S. at 782; *Level the Playing Field v. FEC*, 961 F.3d 462, 464 (D.C. Cir. 2020) (quoting *Hagelin v. FEC*, 411 F.3d 237, 242 (D.C. Cir. 2005)).

7. The Renewed Order violates the National Environmental Policy Act ("NEPA") because it fails to assess the environmental consequences of a major federal action significantly affecting the human environment. 42 U.S.C. § 4321, *et seq.*; 10 CFR § 1021.103.

V. Request For Rehearing

The Department must grant rehearing and rescind the Renewed Order because it suffers from numerous legal and factual deficiencies. Ignoring the legal standards that constrain the exercise of emergency authority under Section 202(c), and acting in

disregard of the facts, the Renewed Order improperly impinges on state authority over resource planning decisions, fails to present substantial evidence of an emergency, imposes unreasonable and unnecessary costs, fails to include required provisions to minimize environmental harms, and advances the administration's preferred energy source with no reasonable basis. For these reasons, the Renewed Order is contrary to law, arbitrary and capricious, and unsupported by substantial evidence. The Department should withdraw it. To the extent the Department intends to rely on the facts and arguments presented in the Original Order to substantiate an emergency during the period of the Renewed Order, the arguments of the State of Colorado in its Original Request of the Original Order are incorporated herein.[81]

A. The Renewed Order is contrary to law because it improperly expands the use of Section 202(c)'s emergency authority beyond the limited scope set forth in the FPA.

Section 202(c) authorizes the Department to command action from a utility unconstrained by many of the core procedural safeguards, jurisdictional boundaries, and substantive limitations normally imposed by the FPA.[82] This power far exceeds the Department's normal authority, and is therefore restricted to the extraordinary and limited circumstances set forth in the statute.[83] The FPA's statutory text and structure, along with the Department's regulations, historic practice, and case law interpreting the FPA all make clear that any such event, including a "shortage of

[81] Exhibit CCC.
[82] *See* 16 U.S.C. § 824a(c).
[83] *Id.* ("[d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes…").

electric energy" or the "demand for electric energy" must be one that constitutes a bona fide "emergency"—*i.e.*, a specific, imminent, unexpected and temporary event. The Renewed Order exceeds the Department's authority because those extraordinary and limited circumstances do not exist here, and the Department is instead attempting to use the Renewed Order to regulate long-term resource adequacy, which is expressly reserved to the states and FERC.

i. The language, history and structure of Section 202(c) limit the Department to addressing specific, imminent, unexpected and temporary supply shortfalls.

Section 202(c)'s text authorizes the Department to act only upon an "emergency."[84] The statute itself does not define "emergency."[85] At the time Section 202(c) was enacted, "emergency" was defined as a "sudden or unexpected appearance or occurrence…An unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency."[86] Contemporary dictionaries likewise define "emergency" as "an unforeseen combination of circumstances or the resulting state that calls for immediate action," or an "urgent need for assistance or relief."[87]

The remainder of Section 202(c)'s plain language also underscores the urgency and immediacy inherent in the word "emergency." The text's use of the present

[84] *Id.*
[85] Although emergency is not defined, the statute does indicate that an emergency includes "the continuance of any war in which the United States is engaged." 16 U.S.C. § 824a(c)(1).
[86] *Emergency*, Webster's New International Dictionary of the English Language (1930).
[87] *Emergency*, Merriam-Webster Dictionary (Jan. 11, 2026); *See* also Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789, 812 n.147 (2025) (noting that dictionaries have given the term "emergency" the "same meaning for many years").

tense underscores its focus on imminent and certain shortfalls, empowering the Department to act only where "an emergency exists."[88] That near-term focus, along with the fact that this Section 202(c) authority is "temporary" authority,[89] precludes use of Section 202(c) to pursue long-term policy goals such as preference for a particular fuel source[90] or interventions to address general concerns about long-term resource adequacy.[91]

The legislative history of the FPA confirms that Congress intended Section 202(c) authority to be used for true emergencies. In a report accompanying the FPA's original passage in 1935, Section 202(c) is described as a "temporary power" to be used in response to "crises:"

> This is a temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose. Drought and other natural emergencies have created similar crises in certain sections of the country; such conditions should find a [f]ederal agency ready to do all that can be done in order to prevent a break-down in electric supply.[92]

Section 202's overall structure also highlights Section 202(c)'s emphasis on imminent, near-term concerns. Section 202 established three tiers of federal

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[88] 16 U.S.C. § 824a(c).
[89] *Id.*
[90] *Richmond Power & Light*, 574 F.2d at 615 (Section 202(c) "is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.").
[91] *See Coalition for Competitive Electricity, Dynergy Inc. v. Zibelman*, 906 F.3d 41, 50 (2018) (citing 16 U.S.C. § 824(b)) (FPA "leaves to the States alone" the authority "to regulate energy production and facilities used for the generation of electric energy"); *see also Arkansas Elec. Co-op Corp. v. Arkansas Public Service Com'n*, 461 U.S. 375, 377 (1983) ("[T]he regulation of utilities is one of the most important of the functions traditionally associated with the police power of the States.").
[92] S. Rep. No. 74-621 at 49 (1935).

involvement in grid coordination. Section 202(a)[93] and Section 202(b)[94] together define and limit the tools by which the federal government may pursue "abundant" energy supplies in the normal course. Section 202(a) states that the federal government may seek "abundant supply of electric energy" by "divid[ing] the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy." Section 202(b) provides a backstop if the voluntary interconnection and coordination provided for in Section 202(a) fails, allowing the federal government to order "physical connection . . . to sell energy or to exchange energy" upon application, and "after an opportunity for hearing."[95] However, Section 202(b) specifically states that the government has "no authority to compel the enlargement of generating facilities for such purposes."[96]

The resulting statutory "machinery for the promotion of the coordination of electric facilities" comprises the following: in subsection (a), an instruction to establish a general framework meant to facilitate "coordination by voluntary action;" in subsection (b), "limited authority to compel interstate utilities to connect their lines and sell or exchange energy," subject to defined procedural and substantive requirements, when "interconnection cannot be secured by voluntary action;" and in subsection (c), "much broader" but "temporary" authority "to compel the connection

[93] 16 U.S.C. § 824a(a).
[94] 16 U.S.C. § 824a(b).
[95] *Id.*
[96] *Id.*

of facilities and the generation, delivery, or interchange of energy during times of war or other emergency."[97]

This structure relies on voluntary action for everyday energy planning, specifies limited authority where that voluntary system fails, and allows for "temporary" central command-and-control only in case of "emergency." Section 202(c) authority applies narrowly to immediate and unavoidable "break-down[s] in electric supply," rather than mere desire for more abundant supply in the future.[98] Interpreting Section 202(c)'s "emergency" powers to encompass longer-term concerns such as potential shortfall years into the future would unwind the careful balance of voluntary, market-driven action and federal authority set out by Congress. Therefore, such an interpretation cannot be squared with the statutory text, history and structure of Section 202 as required by law.

ii. Section 215 of the FPA explicitly assigns federal regulation of long-term resource adequacy to FERC, further emphasizing that the Department's Section 202(c) authority is limited to imminent emergencies.

Section 215 of the FPA, 16 U.S.C. § 824o ("Section 215"), which delineates the scope of federal power to enforce mandatory long-term reliability requirements, confirms that Section 202(c) cannot be used to enforce the Department's preference for long-term reliability solutions. Congress added Section 215 to the FPA in 2005 precisely because the FPA as it then existed, which included Section 202(c), did not provide the federal government with the power to enforce measures designed to

[97] S. Rep. No. 74-621 at 49 (1935).
[98] *Id.*

ensure broad, long-term reliability.[99] Implementation of Section 215, including the approval and enforcement of reliability standards for all entities operating in the bulk power system, is left to FERC and its designated ERO, not the Department.[100]

By enacting Section 215, Congress newly created a comprehensive and carefully circumscribed scheme to allow FERC—not the Department—to address long-term reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent "of the users and owners and operators of the bulk-power system" but with "fair stakeholder representation."[101] FERC may approve or remand those standards (but not replace them with its own) and must "give due weight" to NERC's "technical expertise" while independently assessing effects on "competition."[102] Section 215 specifies enforcement mechanisms and procedures for reliability standards and carefully preserves state authority over "the construction of additional generation" and

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[99] *See* Rules Concerning Certification of the ERO; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards, 70 Fed. Reg. 53117, 53118 (Sept. 7, 2005) ("In 2001, President Bush proposed making Electric Reliability Standards mandatory and enforceable[,]" leading to enactment of Section 215 in 2005); National Energy Policy Development Group, *Reliable, Affordable, and Environmentally Sound Energy for America's Future* (May 2001) at 7-6 (noting that "[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country" and that "[o]ne factor limiting reliability is the lack of enforceable reliability standards" because "the reliability of the U.S. transmission grid has depended entirely on voluntary compliance," and then recommending "legislation providing for enforcement" of reliability standards) (emphasis added); S. Rep. No. 109-78,109th Cong., 1st Sess. at 48, Section 1211 (2005) (Section 215 "changes our current voluntary rules system to a mandatory rules system" for long-term reliability); *see Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005, "the reliability of the nation's bulk-power system depended on participants' voluntary compliance with industry standards").

[100] 16 U.S.C. § 824o.

[101] 16 U.S.C. § 824o(c)(2)(A); s*ee also id*. § 824o(a)(3) (defining reliability standards as "a requirement … to provide for reliable operation of the bulk-power system").

[102] *Id*. § 824o(d)(2)-(4).

regulation of in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards.[103]

Interpreting Section 202(c) to permit the Department to mandate generation based on its determination that non-imminent and unsubstantiated reliability concerns create an "emergency" would effectively allow the Department to bypass Section 215's procedural safeguards, constraints on federal authority, and protection of state power over long-term reliability. This would impermissibly contradict Congress' clear intent as expressed in its more recent reliability-specific provisions, enacted with the understanding that the Department had no authority to address long-term reliability through Section 202(c).[104] "Congress's specific and limited enumeration of [agency] power" over a particular matter in one section of the FPA "is strong evidence that [a separate section] confers no such authority on [an agency]."[105] Congress has, in Section 215, directly established the mechanisms by which the federal government may compel action to ensure long-term electric-system reliability, and that authority does not rest with the Department. In so doing, Congress has confirmed that the word "emergency," as used in Section 202(c), does not extend to long-term reliability concerns and only applies to specific, imminent, unexpected and temporary events.

[103] *Id*. §§ 824o(e), -(i)-(j).
[104] *See also FDA v. Brown & Williamson Tobacco Corp*., 529 U.S. 120, 121 (2000) ("The meaning of one statute may be affected by other Acts, particularly where Congress has spoken subsequently and more specifically to the topic at hand.").
[105] *Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401 (D.C. Cir. 2004).

iii. The Renewed Order is arbitrary, capricious and contrary to law because it contradicts the Department's regulations interpreting Section 202(c) and its historic practice in applying Section 202(c).

The Department's regulations confirm that Section 202(c)'s authority is confined to imminent and unexpected resource shortages rather than long-term reliability concerns. Those regulations define "emergency" for the purposes of Section 202(c) to mean circumstances that arise suddenly and unexpectedly:

> "Emergency," as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected "entity" to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities.[106]

This focus on specific events like weather conditions, acts of God, or unforeseen circumstances outside of the power of the affected entity to prevent, along with the reference to a "sudden increase in customer demand" producing a "specific inadequate power supply situation,"[107] forecloses the Department from using 202(c) authority to address vague long-term supply and reliability issues, such as those articulated in the Renewed Order.

This need for specificity is repeated in the Department's regulations defining an inadequate energy supply: "[a] system may be considered to have inadequate"

[106] 10 C.F.R. § 205.371.
[107] *Id.*

supply when "the projected energy deficiency…will cause the applicant [for a 202(c) Order] to be unable to meet its normal peak load requirements based upon use of all of its otherwise available resources so that it is unable to supply adequate electric service to its ultimate customers."[108] An emergency may exist where past planning failures produce an immediate, present-tense shortfall, but the Department has no authority to commandeer long-term planning merely because it deems current plans inadequate to meet long-term needs.[109] As the Department stated when it promulgated these regulations, the statute allows the Department to provide "assistance [to a utility] during a period of unexpected inadequate supply of electricity," but does not empower it to "solve long-term problems."[110]

Until 2025, the Department's orders complied with this regulatory scheme, and the agency used its Section 202(c) authority only in response to concrete, particularized emergencies, subject to narrow, appropriate limitations. Established "practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred."[111] Until recently, the Department has used Section 202(c) to address specific, imminent, and unexpected shortages, never to address longer-term

[108] 10 C.F.R. § 205.375.
[109] *See id.* (requiring present inability to meet demand to demonstrate inadequate energy supply).
[110] Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39984, 39985–86 (Aug. 6, 1981).
[111] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941).

reliability concerns or demand forecasts.[112] As pointed out by the Congressional Research Service, the orders issued by the Department in May 2025 (and subsequently renewed) to keep coal plants open "all involve[d] seemingly new interpretations of the emergency authority."[113] The Renewed Order at issue in this proceeding continues this improper use of Section 202(c).

Similarly, before 2025, the Department used Section 202(c) on only three occasions to delay the retirement of generation facilities.[114] Each case met the following four criteria: (1) the order was requested by a system operator or governmental body; (2) the generation facility had ceased or would soon cease operation due to an inability to comply with environmental laws; (3) the request aimed to address a concrete and particularized emergency threatening an imminent

[112] *See, e.g.*, Department, Order No. 202-22-4 (Dec. 24, 2022), at 1 (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between December 23 and December 26); Department, Order No. 202-20-2 (Sept. 6, 2020) (responding to shortages produced by ongoing extreme heat and wildfires); *see also* Rolsma, 57 Conn. L. Rev. at 803-4 (describing "sparing[]" use of Section 202(c) outside of wartime shortages during the twentieth century).

[113] Cong. Research Serv., *Federal Power Act: The Department of Energy's Emergency Authority*, CRS Report No. R48568, at 3 (June 12, 2025).

[114] In 2005, the Department issued an order directing the continued operation of a facility in Alexandria, VA, after the facility was abruptly closed based on noncompliance with its air permit. The order only applied when one or both of the 230 kv transmission lines serving downtown D.C. were out of service. Department, Order No. 202-05-3 (Dec. 20, 2005). In 2017, an Oklahoma state agency asked the Department to direct the continued operation of a unit that would otherwise close because the unit was needed to provide dynamic reactive power support to the local grid, as confirmed by its reliability coordinator. The unit was needed because another unit at the station had been struck by lightning, and the third unit's construction had been delayed due to flooding delaying essential project materials. The Department subsequently ordered the unit to remain in operation for 90 days or until one of the other two units came online, to provide dynamic reactive power support when called upon by its reliability coordinator. Department, Order No. 202-17-1 (Apr. 14, 2017). Finally, in 2017, two Virginia utilities asked the Department to direct the continued operation of two units of a power station because they were necessary to prevent uncontrolled power disruptions and shedding of critical load. Letter from PJM Interconnection, LLC, to the Department (Aug. 24, 2017).

loss of load; and (4) the Department tailored its order to go no further than necessary to address the emergency.

The Department's unexplained deviation from its prior interpretation of the statute, as demonstrated through its past practice, is unlawful, arbitrary and capricious.[115] And the Department cannot deviate from its regulations without conducting new notice and comment rulemaking and providing a reasonable basis for any change.[116] A cornerstone of administrative law is "that an agency must provide[ ] a reasoned explanation for departing from precedent or treating similar situations differently."[117] For this reason, "an interpretation of a legislative rule cannot be modified without the notice and comment procedure that would be required to change the underlying regulation—otherwise, an agency could easily evade notice and comment requirements by amending a rule under the guise of reinterpreting it."[118] The Department has not undertaken any such notice and comment procedure here and has not provided any reasoned justification for its recent departure from the binding requirements and interpretations of its governing statute and regulations.

[115] *F.C.C. v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009) ("To be sure, the requirement that an agency provide reasoned explanation for its action would ordinarily demand that it display awareness that it *is* changing position.").
[116] *See* 5 U.S.C. § 553; *F.C.C.,* 566 U.S. at 515 (holding that an agency cannot simply change position on an issue without "a reasoned explanation" and "awareness that it is changing position.").
[117] *New England Power Generators Ass., Inc. v. FERC*, 881 F.3d 202, 210–12 (D.C. Cir. 2018) (quoting *W. Deptford Energy, LLC v. FERC*, 766 F.3d 10, 20 (D.C. Cir. 2014)).
[118] *Env't Integrity Project v. EPA,* 425 F.3d 992, 995 (D.C. Cir. 2005) (internal citations omitted); *see also Center for Biological Diversity v. Haaland*, 998 F.3d 1061, 1067 (9th Cir. 2021) (internal citations omitted) ("When an agency changes its position, it must: (1) "display [ ] awareness that it is changing position," (2) "show "the new policy is permissible under the statute," (3) "believe[ ]" the new policy is better, and (4) provide "good reasons" for the new policy.").

iv. Courts have found that the Department's use of Section 202(c) is limited to true emergencies and the Department is bound by the courts' statutory interpretation.

There is little case law on Section 202(c). However, two decisions that have addressed the Department's authority under Section 202(c) both recognize that the Department's power under Section 202(c) is limited to specific, imminent, unexpected and temporary events.

First, during the 1973 oil embargo, the Federal Power Commission called for a voluntary transfer of electricity from non-oil power plants to areas of the country that relied heavily on oil, but the New England Power Pool petitioned for a Section 202(c) order because it was not convinced the voluntary program would work.[119] The Commission declined to issue a Section 202(c) order, and instead facilitated an agreement between state commissions and supplying utilities.[120] In *Richmond Power and Light of City of Richmond, Indiana v. FERC*, the D.C. Circuit upheld the Commission's decision to not invoke Section 202(c).[121] The utility argued that the country's dependence on foreign oil, and the high cost and uncertain supply of foreign oil, left the country with a continuing emergency, but the court agreed with the Commission's argument that the facilitated agreement had worked, service was never interrupted, and there was no need for a Section 202(c) order.[122] The court highlighted that the statute "speaks of 'temporary' emergencies, epitomized by

[119] *Richmond Power & Light*, 574 F.2d at 613.
[120] *Id*.
[121] *Id.* at 614.
[122] *Id.* at 615.

wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply[.]"[123] The court upheld the Commission's view that Section 202(c) cannot be used when "supply is adequate but a means of fueling its production is in disfavor."[124]

The Eighth Circuit Court of Appeals has also held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power Co. v. Fed. Power Comm'n*., a utility insisted a Section 202(c) order was necessary to properly order the utility to connect to a municipal power provider. The demand for electricity in the city had increased, and the peak load of the municipal power provider was high enough that both of its two generators would likely be needed simultaneously in the near future, which could cause a possible loss of service if one of them malfunctioned during a peak period.[125] Instead of issuing a Section 202(c) order, the Commission issued an order under Section 202(b), which the utility argued was incorrect.[126]

In upholding the Commission's decision, the court distinguished between an emergency that is likely to occur and one that is actually occurring, concluding that Section 202(b) applies to the former, while Section 202(c) applies to the latter:

> On its face, § 202(c) enables the Commission to react to a war or national disaster and order immediate interconnection of the facilities to maintain electrical service during such emergency. . . On the other hand, § 202(b) applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission.[127]

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[123] *Id*.
[124] *Id.*
[125] *Otter Tail Power*, 429 F.2d at 233-234.
[126] *Id*.
[127] *Id*. at 234.

Therefore, the court agreed that a potential crisis in the foreseeable future was not an emergency, making this current situation "just the type of situation to fit into a Section 202(b) hearing rather than a Section 202(c)."[128]

Because courts, not agencies, decide "all relevant questions of law" arising on review of agency actions, the Department is bound by these courts' "best reading" of the statutory language.[129]

B. Section 202(c) does not vest the Department with general regulatory authority over resource adequacy, which is regulated by the states and FERC under other provisions of the FPA.

The FPA preserves states' authority over generation facilities and resource adequacy planning, and Section 202(c) does not vest the Department with general regulatory authority over resource adequacy. Under the FPA, states are responsible for their own resource adequacy and decisions about generation facilities, and FERC is responsible for assuring the reliability of the nation's bulk power system, including through its oversight of RTOs and ISOs. The Department itself has recognized that "resource adequacy planning and capacity requirements[] have traditionally been the domain of state regulatory commissions, NERC-certified Regional Entities, and RTOs/ISOs."[130] Because there is no imminent shortfall or other circumstance constituting an emergency, the Renewed Order is an illegal attempt to regulate long-term resource adequacy by misusing the Department's Section 202(c) authority.

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[128] *Id.*
[129] *Loper Bright Enterprises v. Raimondo*, 603 U.S. 369, 392, 399-400 (2024).
[130] Research Power Corp., Order No. EA-365-C, Order Authorizing Electricity Exports to Canada, at 5 (Dep't of Energy Oct. 21, 2025).

i. The Renewed Order's attempt to regulate long-term resource adequacy and energy production is intruding on FERC and state authority.

The Department is attempting to regulate long-term resource adequacy and energy production under the guise of a Section 202(c) emergency and is therefore intruding on FERC and state authority.

It is clear from the Renewed Order that the Department is using its Section 202(c) authority for circumstances beyond actual emergencies. The Renewed Order repeatedly references long-term reliability. The Department's determination that an emergency exists rests on the assertion of a long-term concern that "increasing demand and shortage from accelerated retirement of generation facilities . . . could lead to the loss of power to homes, and businesses" that is "likely to continue in subsequent years."[131] The Renewed Order admits that the WECC-Rocky mountain region, where it has currently declared there to be an energy emergency, "is at normal risk of energy shortfalls over the next five years."[132] As evidence of an energy emergency, the Renewed Order cites only the 2025 LTRA's statement regarding potential shortfalls in the WECC-Rocky Mountain region beginning in 2034 and that Colorado will have a certain amount of coal-fired generating capacity retired by 2029.[133] Demand growth and retirements occurring over the next decade fall into the realm of long-term resource planning, not a Section 202(c) emergency, which must be imminent, unexpected, sudden, and temporary.[134]

[131] Exhibit TT, at 7.
[132] *Id.*, at 4.
[133] *Id*.
[134] *See supra*, Section V.A.

Regulating long-term resource adequacy is outside the scope of the Department's Section 202(c) authority. The structure and language of the FPA reflect Congress' deliberate choice to preserve the states' traditional authority over generating facilities and to limit the Department's emergency authority. The FPA states that "the Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy…"[135] Congress also recognized the states' exclusive authority over generating facilities in Section 202(b), which provides that FERC's interconnection authority does not include the power to "compel the enlargement of generating facilities for such purposes."[136] FERC's role in regulating electricity generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the [s]tates."[137]

Pursuant to the FPA, "[t]he states are thus authorized to regulate energy production . . . and facilities used for the generation of electric energy."[138] Decisions around what facilities to build, whether they remain feasible, and retail rates are areas governed by the states.[139] Courts have held that Section 201(b)(1) reserves to the states authority over electric generating facilities, including that states retain the

[135] 16 U.S.C. § 824(b)(1).
[136] 16 U.S.C. § 824a(b).
[137] 16 U.S.C. § 824(a).
[138] *Coal. for Competitive Elec.,* 906 F.3d at 50.
[139] *Pac. Gas & Elec. Co. v. State Energy Res. Conservation and Dev. Comm'n*, 461 U.S. 190, 205 (1983).

right "to require the retirement of existing generators" or to take any other action in their "role as regulators of generation facilities."[140] FERC has acknowledged that "[r]esource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsive for procuring adequate capacity to serve loads within their respective jurisdictions."[141] As relevant to Craig Unit 1, because SPP does not have a capacity market, states are still required to ensure utilities have sufficient generation capacity to meet their needs and SPP determines when to dispatch it. While many RTOs or ISOs have a centralized capacity market, SPP instead uses a resource adequacy requirement that establishes minimum capacity levels but maintains traditional state authority over how to meet those minimum levels.

The electric power sector is governed by longstanding principles of cooperative federalism encouraged in Section 209(b) of the FPA, which explicitly declares that FERC may consult with states "regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction of such State commission and of the Commission."[142] FERC has embraced these cooperative federalism principles and developed long-standing consultation practices with the states, including through creation of a Joint Federal-State Task Force,[143] and more recently, a Federal-State Current Issues Collaborative

[140] *Conn. Dep't of Pub. Util.*, 569 F.3d at 481; *see also Hughes*, 578 U.S. at 155.
[141] *Devon Power LLC, et al.*, 109 FERC ¶ 61,154, at 47 (2004).
[142] 16 U.S.C. § 824h(b).
[143] FERC, *Joint Federal-State Task Force on Electric Transmission* (Sept. 3, 2025).

which was formed due to the success of the Task Force.[144] The importance of this cooperation is evident in the Department's own Resource Adequacy Report, which flagged that it could have benefitted greatly from cooperation with the states due to the "in-depth engineering assessments which occur at the regional and utility level."[145]

In the Renewed Order, the Department seeks to substitute its own judgment about which resources should be employed to maintain resource adequacy for the states' decisions, despite these decisions resting firmly in the jurisdiction of the states. Section 202(c) does not provide the Department with the authority to mandate that resources remain running to address long-term resource adequacy. If Congress intended to vest regulatory authority over long-term resource adequacy in Section 202(c) and displace state law, it would have needed to make that intent "unmistakably clear."[146] Section 202(c) says that the Department may "require by order . . . such generation . . . of electric energy as in its judgment will best meet the emergency and serve the public interest."[147] Empowering the Department to generally determine which power plants may retire across every utility and independent power producer in the entire country would have profound implications for rates, state

[144] FERC, *Federal-State Current Issues Collaborative* (Jan. 21, 2026).
[145] Department, *Resource Adequacy Report Evaluating the Reliability and Security of the United States Electric Grid* (July 2025) at 2.
[146] *Gregory v. Ashcroft,* 501 U.S. 452, 460 (1991) (The clear statement rule requires Congress to make its intent unmistakably clear if it intends a statute to alter the usual constitutional balance between the federal government and the states.); *see also DeMarco v. Holy Cross High Sch.*, 4 F.3d 166, 169 (2d Cir. 1993) (Congress must express an affirmative intention to use a statute to alter the federal balance.).
[147] 16 U.S.C. § 824a(c)(1).

sovereignty, and a broad array of other state policy and stakeholder interests. If Congress had intended to do that, it would not have done so through the only provision in the FPA that empowers the Department to act outside normal procedural safeguards.

The Supreme Court has rejected statutory interpretations where an agency "claim[s] to discover in a long-extant statute an unheralded power representing a transformative expansion in its regulatory authority."[148] The Department may not radically reinterpret a 90-year-old statute to manufacture a basis to exercise much broader authority than it ever has in the past. Previous exercises of Section 202(c) authority have been at the request of a system operator or governmental body and in a manner narrowly tailored to respond to a concrete and particularized emergency. Prior to the current administration, the Department has never issued a Section 202(c) order to impose its policy preferences to contravene the judgment of those bodies properly responsible for ensuring resource adequacy, *i.e.*, the states and FERC. For these reasons, the Renewed Order should be withdrawn.

C. The Renewed Order fails to present substantial evidence for its emergency determination and ignores critical facts.

Agencies "must examine the relevant data and articulate a satisfactory explanation for [their] actions, including a rational connection between the facts found and the choice made[,]" and make findings that are supported by substantial

[148] *W. Virginia v. EPA*, 597 U.S. 697, 724, (2022) (quoting *Util. Air. Regul. Grp. V. E.P.A.*, 573 U.S. 302, 324 (2014)) (internal quotations omitted).

evidence.[149] Substantial evidence is "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion."[150] Similarly, orders under the FPA must reflect "a principled and reasoned decision supported by the evidentiary record."[151] Here, the Department failed to provide evidence of an imminent resource adequacy shortfall, making the Renewed Order contrary to law.

The Renewed Order cites the following purported evidence of an emergency: the 2025 LTRA, WECC's 2025 Western Assessment of Resource Adequacy, and the Department's Resource Adequacy Report; generation retirements and summer resource adequacy in Colorado; the Grid Reliability and Energy Emergency Executive Orders; and data center load growth.[152] Contrary to the Renewed Order's claims, these reports and observations, whether considered separately or together, do not provide sufficient evidence of an energy emergency in the WECC-Rocky Mountain assessment area.

i. NERC's assessments do not establish that there is an energy emergency in the areas served by Craig Unit 1.

The Renewed Order cites the NERC 2025 LTRA's statements that the WECC-Rocky Mountain assessment area has an anticipated reserve margin that falls below the reference margin level in Summer 2034 and Summer 2035, and Winter 2034-2035, that the area faces challenges from an aging thermal resource fleet, and that both

[149] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (quoting *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962)).
[150] *Chritton*, 888 F.2d at 856 (quoting *Refrigerated Transport Co., Inc. v. I.C.C.*, 616 F.2d 748, 751 (5th Cir.1980) (quoting *Chem–Haulers, Inc. v. United States*, 536 F.2d 610, 617 (5th Cir.1976)).
[151] *Emera Maine*, 854 F.3d at 22.
[152] Exhibit TT.

solar and wind variability are year-round concerns.[153] The Renewed Order relies on these statements to assert the WECC-Rocky Mountain assessment area is experiencing an energy emergency. This mischaracterizes and misapplies the 2025 LTRA's conclusions. By failing to consider relevant facts and to support its findings with substantial evidence, the Department's Renewed Order is contrary to law.

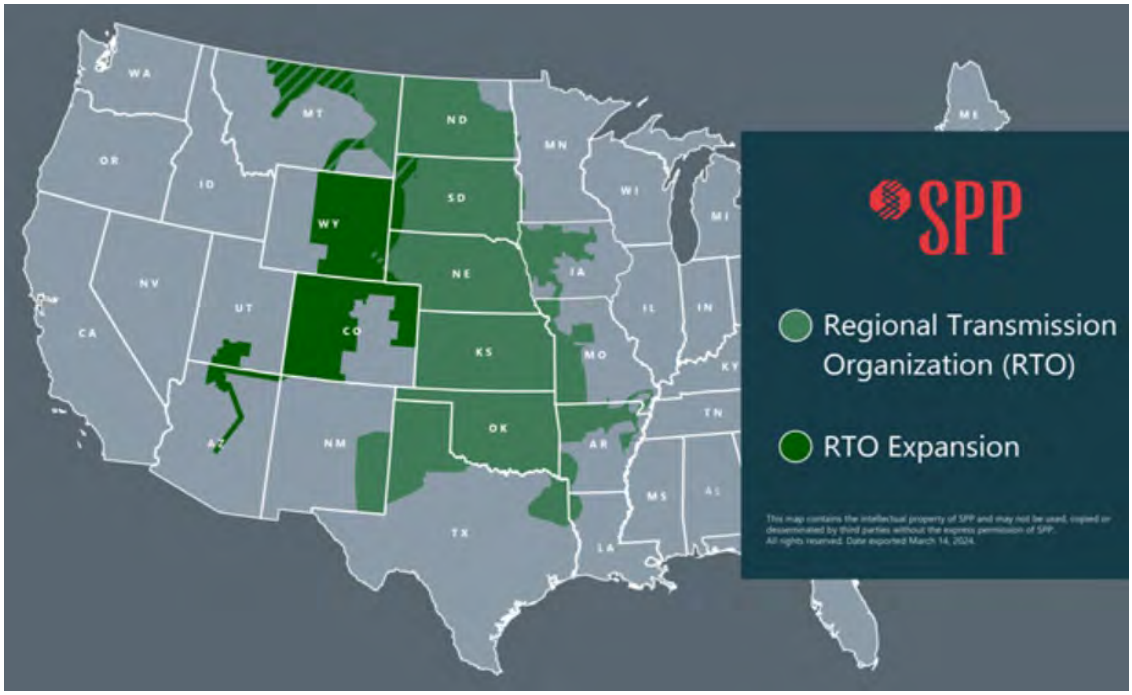
The Department's reliance on the 2025 LTRA as evidence of an emergency is fundamentally flawed. NERC serves an important advisory role by providing recommendations about risks to the grid, but ultimately, determinations about generation resources remain within state authority.[154] Importantly, NERC's reports do not examine regions at the level of granularity that would be required to determine whether a particular resource is essential for regional resource adequacy. The reports only provide the anticipated planning reserve margins of large regions as a whole. The purpose of NERC assessments is to identify for grid operators constraints that might arise and implicate grid reliability if not mitigated.[155] Thus, even "at risk" designations are not grid emergencies. They merely reflect potential areas of future concern so that the relevant grid operators and planners for the applicable region can consider whether mitigation measures are necessary to maintain grid reliability, under their set procedures. Thus, the purpose of NERC's LTRAs is to assess the adequacy of planned resources to meet electricity demand across North America over the next ten

[153] *Id.*, at 4.
[154] NERC, *Reliability Assessments* (2026).
[155] Exhibit L.

years so that utilities, states, and RTOs can adjust their planning accordingly.[156] The 2025 LTRA does not address short-term reliability issues. Therefore, this report cannot support a decision by the Department to keep one power plant open in the name of a general region-wide emergency.

The Department's choice to rely on the 2025 LTRA is also flawed because the 2025 LTRA does not account for the fact that Tri-State and PRPA have joined the SPP RTO. SPP's new footprint after its April 1, 2026, western expansion is demonstrated in the figure below:

Figure 1: SPP Expanded RTO Footprint[157]

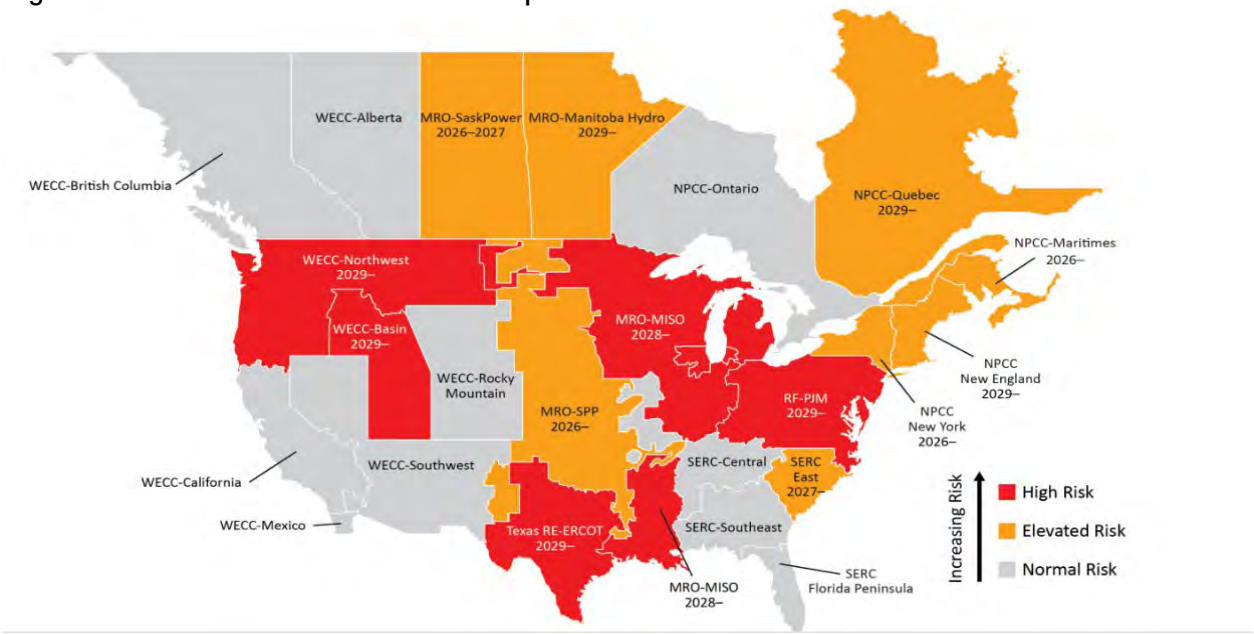


[156] Exhibit K; Exhibit HHH (Cook, A., NERC to OMS: Long-term Assessment not a Predictor of Risk (Feb. 10, 2026)), at 2 (reporting that NERC representatives have explained the long-term reliability assessment "is not a prediction in any way," and have noted that over the years, areas labeled "high risk" have not experienced emergency shortages); Organization of MISO States, Inc., Minutes of the Board of Directors Meeting (Feb. 9, 2026) (approved).

[157] SPP, *RTO Expansion*, Western Services (Apr. 1, 2026) (map at top of page).

The other NERC 2025 LTRA assessment areas match up with RTO and ISO footprints, as shown in the map below:

Figure 2: NERC Assessment Areas Map[158]



But the 2025 LTRA assessment does not account for the westward expansion of the SPP RTO because it occurred after the publication of the 2025 LTRA. The MRO-SPP and WECC-Rocky Mountain assessment area no longer accurately reflect operational and planning realities, as well as RTO footprints. Thus, it is unreasoned for the Department to rely on the 2025 LTRA as substantial evidence of a reliability concern in the WECC-Rocky Mountain assessment area.

[158] Exhibit WW, at 8.

Even if it were appropriate for the Department to rely on the 2025 LTRA, that assessment does not actually demonstrate an emergency for the WECC-Rocky Mountain assessment area, contrary to the Renewed Order's claims. First, it is unclear why the Renewed Order states that the WECC-Rocky Mountain assessment area faces challenges from an aging thermal resource fleet. The 2025 LTRA does not list that as a concern for the WECC-Rocky Mountain assessment area.[159]

In terms of resource adequacy in the WECC-Rocky Mountain region, the Renewed Order itself states that "NERC assessed that the WECC[-]Rocky Mountain region, which includes Colorado, is at a normal risk of energy shortfalls over the next five years," but goes on to selectively cite the fact that the assessment area's anticipated reserve margin falls below the reference margin level for the first time in Summer 2034.[160] A potential shortfall starting eight years from now does not provide sufficient evidence to support an emergency declaration for the 90 days covered by the Renewed Order. And this potential shortfall was projected only because "not enough resources have progressed into the interconnection queue for these later years in the assessment period."[161] There is more than sufficient time for the usual state and market planning processes to address this potential shortfall over the next eight years before it is projected to occur.

[159] *See id.*, at 137, 143, 150, 159, 166 (listing an aging thermal resource fleet as a concern for the WECC-Alberta, WECC-Basin, WECC-California, WECC-Northwest, and WECC Southwest assessment areas). The Department's cite to page 161 does not describe an aging thermal resource fleet as a concern for WECC-Rocky Mountain assessment area. Exhibit TT, at n. 17.
[160] *Id.*, at 4.
[161] Exhibit WW, at 161.

The Renewed Order also ignores that the WECC-Rocky Mountain assessment area has anticipated reserve margins (even when including announced generation retirements) of 51.3% for 2026, 60% for 2027, and 53.2% for 2028, and that the 2025 LTRA found that the WECC-Rocky Mountain assessment area's "planned resources meet demand and reliability margins for all hours."[162]

The 2025 LTRA does not provide substantial evidence of an energy emergency in the WECC-Rocky Mountain assessment area.

ii. WECC's Western Assessment of Resource Adequacy and the Department's Resource Adequacy Report do not demonstrate an emergency.

The Renewed Order also cites the 2025 WECC Western Assessment of Resource Adequacy ("2025 WECC Assessment") to support its declaration of an emergency. Like the 2025 LTRA, the 2025 WECC Assessment does not analyze near-term resource adequacy and instead uses a probabilistic approach to evaluate reliability over the next ten years.[163] This makes the 2025 WECC Assessment inappropriate for providing evidence of an emergency under Section 202(c).

Even if the 2025 WECC Assessment was appropriate evidence for the Department to rely upon, it does not demonstrate an emergency in the areas served by Craig Unit 1 or the WECC-Rocky Mountain assessment area. Once again, the Department selectively cites information from that report.[164] The Renewed Order mentions long-term resource adequacy concerns regarding the Basin and Northwest

[162] *Id.*, at 160, 162.
[163] WECC, *2025 Western Assessment*, WECC Feature (last visited Apr. 27, 2026).
[164] Exhibit TT.

subregions, despite the fact that the Renewed Order only designates an emergency for the WECC-Rocky Mountain subregion.[165] The Renewed Order then fails to acknowledge the 2025 WECC Assessment's findings for the Rocky Mountain subregion, namely that the Rocky Mountain subregion is again designated as normal risk. The subregion does not have demand at risk hours until 2029, and then only in a scenario where only 85% of planned additions are completed and operational on time.[166] Thus, the 2025 WECC Assessment does not provide substantial evidence of an emergency in the WECC-Rocky Mountain assessment area.

Next, the Renewed Order briefly references the Department's Resource Adequacy Report,[167] which purports to provide a uniform methodology for identifying at-risk regions and grid reliability issues and guide reliability interventions. As with other reports cited in the Renewed Order, this Report provides no support for the Department's determination that there is an emergency requiring continued availability of Craig Unit 1 in the next 90 days, or even the next year. The Report assesses the ability of the electric grid to "meet *future* demand through 2030" and is a "*forward-looking* snapshot of resource adequacy."[168] This Report was not designed to assess imminent emergency conditions of the electric grid, and explicitly does not do so.

[165] WECC, 2025 *Western Assessment*, supra.
[166] *Id.*
[167] Exhibit M.
[168] Department, *Resource Adequacy Report Evaluating the Reliability and Security of the United States Electric Grid* (July 2025) at 9 (emphasis added).

Indeed, the Report's only conclusions are for 2030, which is completely irrelevant for an emergency Section 202(c) order issued for 90 days in 2026. The Report finds potential reliability issues in 2030 only under a set of unsupported assumptions that assume unrealistically high load projections stemming from unfounded assumptions about data center load, and assume that utilities virtually cease construction of new generation and transmission resources. Its 2030 projections are at odds with the analyses from NERC and WECC, as well as the findings from Colorado's ERP proceedings and utilities' resource adequacy reporting. In any case, a claimed reliability issue in 2030 cannot justify a 90-day emergency order in 2026. Forcing ratepayers to pay to keep generation online that is not needed, simply because technology companies may be building more data centers in the future that may need power is arbitrary and violates the FPA's requirement that rates be just and reasonable, especially as other analyses indicate that data center projections may be overblown.[169]

Given its focus on future conditions and unverified assumptions, the Report is not substantial evidence of an emergency under Section 202(c).

iii. State and utility planning processes have ensured that the areas served by Craig Unit 1 will continue to have sufficient capacity without Craig Unit 1.

The Renewed Order notes that Colorado's share of coal generated electricity has fallen from 45% to 25% since 2016, that further coal and natural gas plant

[169] Exhibit SS (Behr, P., *PJM to ratchet down projected AI power demand for eastern US* (Jan. 6 , 2026)); Institute for Policy Integrity, *Fiscal Year 2025 Annual Report*; London Economics International LLC, *Uncertainty and Upward Bias are Inherent in Data center Electricity Demand Projections* (July 7, 2025).

retirements are planned by 2029, that intermittent wind accounts for 5,300 MW of Colorado's electric generating capacity, and that CoPUC Commissioners have discussed resource adequacy concerns for Summer 2026 as evidence of an energy emergency in the WECC-Rocky Mountain assessment area.[170] However, the Renewed Order does not provide any evidence that any of these factors have resulted in a resource shortfall in Colorado. Pursuant to the authority reserved to the states by the FPA, Colorado has robust electric resource planning processes that ensure resource adequacy and grid reliability. Tri-State and PRPA, the two co-owners of Tri-State that are both located in Colorado and members of SPP, also have robust electric resource planning processes that accounted for the retirement of Craig Unit 1.

a. Colorado's robust planning process ensures sufficient capacity for the State's utility customers.

For decades, Colorado has implemented robust and successful electric resource planning processes that serve as a model for other states. Colorado's process assesses resource adequacy and reliability across utilities' service territories, requires regulated utilities to use competitive resource solicitations to acquire new resources of multiple fuel types, and ensures that there will be sufficient electricity to meet expected load, even with planned plant closures.[171]

As part of Colorado's overall energy planning framework, each investor-owned retail electric utility and wholesale electric generation and transmission cooperative is required to submit to the CoPUC an application for approval of an ERP.[172] Each

[170] Exhibit TT, at 4-5.
[171] *See* Exhibit C, ¶¶ 12-17.
[172] § 40-2-125.5, Colo. Rev. Stat.; 4 Colo. Code Regs. §§ 723-3-3603(a), -3605(a).

Colorado ERP proceeding thoroughly considers resource adequacy and reliability at multiple stages.[173] In developing their forecasted resource needs, utilities' electric energy and demand forecasts must be completed for each year within the ERP planning period and must include, among other components, the electric demand placed on the utility's system for each hour of the day for peak-day, average-day, and representative off-peak days for each calendar month.[174] Utilities must "develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period[,] . . . . including base case, high, and low" demand growth scenarios.[175] Since the announcement of Craig Unit 1's retirement in 2016, the CoPUC has received annual resource planning reports from Tri-State and Public Service, and has conducted two adjudicated resource planning proceedings for Tri-State's system and three for Public Service's system, with administrative records totaling in the tens of thousands or hundreds of thousands of pages. All of these proceedings have included the planned Craig Unit 1 retirement as a foundational assumption in forecasting, modeling, and portfolio selection.

In an ERP proceeding, the utility must describe and justify the means by which it assesses the desired level of system reliability, and it must propose target planning reserve margins for each forecasted scenario.[176] Utilities' planning reserve margin studies employ probabilistic modeling to determine the amount of capacity necessary

[173] *Id*.
[174] 4 Colo. Code Regs. § 723-3-3605(b).
[175] *Id.* at -(b)(II).
[176] 4 Colo. Code Regs. § 723-3-3605(e).

to maintain a certain level of reliability, for example a Loss of Load Expectation of 0.1 days/year. The studies must account for a wide variety of risks, "includ[ing] risks associated with: the development of generation; losses of generation capacity . . . ., losses of transmission capability; [and] risks due to known or reasonably expected changes in environmental regulatory requirements[.]"[177] Planning reserve margin studies also rely on thorough analyses, for each resource type, of the Effective Load Carrying Capability ("ELCC"), or the amount of dependable capacity that can be counted on by the system for resource adequacy purposes.[178] Utilities must present contingency plans for the acquisition of additional resources in the event demand increases or expected generation resources are not developed.[179] "The additional generation must be able to [ ] meet system needs, including availability or dispatchability at certain hours of the day."[180]

Upon completion of a resource solicitation, the utility presents a number of potential resource portfolios. Included in this presentation are the results of additional reliability checks, which further ensure resource adequacy and reliability by demonstrating that each portfolio satisfies relevant metrics such as meeting the required planning reserve margin, meeting a Loss of Load Hours target and meeting an Annual Expected Unserved Energy target.[181] After opportunities for stakeholder input, the CoPUC issues a decision establishing the final cost-effective resource plan. In

[177] *Id*. at -(e)(II).
[178] Exhibit C, ¶¶ 23, 43, 54.
[179] 4 Colo. Code Regs. § 723-3-3605(e)(III).
[180] Exhibit C.
[181] *E.g.*, Exhibit J, at 94-95.

making this decision the CoPUC considers various statutory factors, including whether the resource plan meets the energy policy goals of Colorado, such as giving full consideration to cost-effective resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.[182]

Colorado's electric resource planning process also allows for the filing of interim ERPs and certificates of public convenience and necessity to fill generation needs not identified or fully satisfied by ERPs completed on the regular cadence.[183] This "allow[s] electric utilities and the State to quickly respond to changes in load or available resources."[184]

The Renewed Order states that CoPUC commissioners "have expressed concerns about the ability of certain utilities to meet projected summer 2026 loads[,]" citing a March 26, 2026, RTO Insider article titled *Comanche 3 Repair Delay Raises RA Concerns in Colorado*.[185] The Renewed Order's reliance on the article is overbroad, misplaced, and premature.

The article discusses just one Colorado utility - Public Service – and its projected loads and resources for Summer 2026. Discussions around Summer 2026 loads have been prompted in significant part by the extended unplanned outage of coal-fired Comanche Unit 3, which has been offline since August 12, 2025. As stated in the article, CoPUC commissioners noted Public Service's forecasted loads and

[182] 4 Colo. Code Regs. § 723-3-3605(h); § 40-2-134, Colo. Rev. Stat.
[183] 4 Colo. Code Regs. §§ 723-3-3603(a), 3605(a)(II); Exhibit C.
[184] *Id.*, ¶ 16.
[185] Exhibit TT, at 6.

resources and required the utility to quickly explore additional capacity resources. The CoPUC's actions are part of an ongoing proceeding to address the impacts of Comanche Unit 3's unavailability, including requiring Public Service to fully explain its plan for meeting forecasted load prior to the summer months of 2026. As noted in the RTO Insider article, Public Service is considering potential strategies to increase capacity, and these include market purchases, unit extensions and uprates, extensions of power purchase agreements, the acquisition or acceleration of additional generation resources, pre-construction development assets, and demand response.

The Department's citation to a single news article regarding discussions about one Colorado utility is not substantial evidence of an emergency under Section 202(c). The Renewed Order provides no explanation of why concerns raised in an ongoing dialogue with a utility would justify continued operation of Craig Unit 1. This is particularly true where the Department disregards the CoPUC's other conclusions regarding system reliability after Craig Unit 1's retirement.[186] The Department also disregards that the article describes discussions that are representative of the regulatory process and the CoPUC's careful attention to resource adequacy issues. As demonstrated by Colorado's robust and iterative resource planning processes, the CoPUC closely monitors resource adequacy issues to ensure regulated utilities can provide reliable service. The issues described in the RTO Insider article are subject to

[186] Exhibit E, ¶ 116. The CoPUC made a factual finding "that Craig Unit 1 is not required for reliability or resource adequacy purposes…".

the CoPUC's timely regulatory process; by the time the Renewed Order was issued, the CoPUC had already directed Public Service to present its full contingency plan to meet forecasted load. The Renewed Order fails to present any evidence that a capacity shortfall will occur in summer 2026, it merely references a discussion of forecasted loads and resources that the CoPUC is already taking steps to address.

b. Tri-State and PRPA demonstrate a reliable resource portfolio after Craig Unit 1's retirement.

The extensive planning processes conducted by Tri-State and PRPA, the owners of Craig Unit 1 that have joined SPP, have ensured that the unit's retirement will not negatively impact the reliability of any of their electric grids. All of the utilities are resource adequate for the 90 days covered by the Renewed Order and none of them have expressed a need for Craig Unit 1.

Tri-State's most recent electric resource proceeding[187] concluded in August 2025 with the selection of Tri-State's preferred resource portfolio as the approved cost effective resource plan.[188] The portfolio includes the addition of 700 MW of wind and solar, 650 MW of storage, and 307 MW of gas between 2026-2031, replaces the turbines on one of Tri-State's gas plants to improve its capacity contributions, and maintains the retirement dates of three coal plants (including Craig Unit 1).[189] Tri-State demonstrated that the portfolio meets all reliability metrics, and avoids costly transmission upgrades required by other analyzed portfolios.[190] Tri-State remains in a

[187] Tri-State's planning processes encompass all states in its service territory, including Wyoming and Colorado. *See* Exhibit X, at 6.
[188] Exhibit E, ¶ 90.
[189] Exhibit X, at 6.
[190] Exhibit J.

capacity-long position until 2030 but has planned on the above resource acquisitions to ensure reliability as its coal units retire in 2025, 2028, and 2030 and to maintain progress toward emissions reductions.[191]

Tri-State supported each of the considered resource portfolios with two levels of rigorous reliability metric checks. The first level, intended to meet industry standards, required each portfolio's satisfaction of: (1) the target planning reserve margin for each year in the resource acquisition period, or 22% transitioning to 30.5% in 2028; (2) a Loss of Load Hours maximum of 1 day in 10 years and a maximum of 2.4 hours annually; and (3) an Expected Unserved Energy maximum of less than or equal to 0.4 Gigawatt hours ("GWh") annually.[192] The second level of reliability metrics was applied to the extreme weather event sensitivities to ensure reliable service during likely future weather events, and required that this modeled sensitivity for each portfolio resulted in: (1) no more than 12 hours of expected unserved energy during all extreme weather events modeled in the years 2026-2031; (2) no more than 3 Loss of Load Hours per each year in the years 2026-2031; (3) and an Expected Unserved Energy maximum of 20% of load in any hour.[193] Tri-State demonstrated that each presented resource portfolio met these reliability metrics. For the portfolio approved by the CoPUC, planning reserve margins ranged from 24% in 2025 to 34% in 2031, with

[191] Exhibit W (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E), at 30:15-16.
[192] Exhibit J, at 18.
[193] *Id.*; Exhibit W.

zero Loss of Load Hours and zero annual expected unserved energy during that period.[194]

Tri-State initially proposed the planning reserve margin targets satisfied by each portfolio through a detailed analysis of grid parameters, including the reliability needs of a system transitioning away from coal generation and toward increased reliance on renewables. ELCCs were determined for each resource type to appropriately model each resource's capacity potential for the specifics of Tri-State's system, rather than relying on nameplate capacity.[195] Incorporating these ELCCs and the reliability standard of 0.1 Loss of Load Expectation, Tri-State proposed that after the retirement of the Craig Station and the departure of certain member loads in 2028, the target planning reserve margin be 30.5%, which is considerably higher than its existing and historic reserve margin.[196] These planning reserve margins were carried through to Tri-State's portfolio approved in August 2025.[197]

In summary, every portfolio that Tri-State modeled in its most recent ERP assumed the retirement of Craig Unit 1 at the end of 2025, and every modeled portfolio met all reliability metrics, including Tri-State's approved portfolio.[198] And as specifically found by the CoPUC in its decision approving Tri-State's preferred

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[194] Exhibit J, at 62.
[195] Exhibit OO (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 – Attachment G-1 (Astrape Consulting, Reserve Margin and ELCC Study, Public (Aug. 2, 2023)), at 8.
[196] *Id.*
[197] Exhibit W, at 20:8-15; Exhibit E.
[198] Exhibit J, Table 7: Modeled Retirements (Portfolio 1 - NEE), at 21, Table 32: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 2 – NELG), at 35, Table 28: Modeled Retirements (Portfolio 2 – NELG), at 32, Table 49: Modeled Retirements (Portfolio 3 – FLEX), at 43, Table 70: Modeled Retirements (Portfolio 4 – FLEXSR), at 54, Table 91: Modeled Retirements (Portfolio 5 – NNG), at 75, Table 112: Modeled Retirements (Portfolio 6 – NNGSR), at 75.

portfolio, "Craig Unit 1 is not required for reliability or resource adequacy purposes based on the record in this ERP."[199] Tri-State's most recent ERP progress report, filed on March 17, 2026, confirms that it is progressing with resource contracting.[200] And in its 2026 Electric Resource Adequacy Report, also filed on March 17, 2026, Tri-State demonstrates that it expects to have excess resources for years 2026 through 2035.[201] Tri-State's anticipated excess capacity ranges from 123 MW in 2026 to 95 MW in 2035.[202]

These forecasts are not changed by Tri-State's recent entry into SPP. Tri-State has explained that its assets in the Western Area Colorado Missouri ("WACM") Balancing Authority will be subject to SPP's planning reserve margin requirements.[203] Tri-State intends to compare SPP's requirement to its most recent planning reserve margin requirement and follow the more stringent of the two.[204] Tri-State has stated that entering SPP will be "key for integrating intermittent resources on a large scale and further supporting affordable and reliable operations…"[205]

PRPA, though not overseen by the CoPUC, develops an Integrated Resource Plan ("IRP") to conduct long-term resource planning and ensure resource adequacy.[206] PRPA ran all of its scenarios to meet a planning reserve margin of 19.9%.[207] With its

[199] Exhibit E, ¶ 116.
[200] Exhibit EEE (CoPUC, Tri-State, *Notice Regarding Phase II Developments,* filed on March 17, 2026, in Proceeding No. 23A-0585E), at 3.
[201] Exhibit VV, Table 1 – Load and Resources, at 4.
[202] *Id.*
[203] Exhibit Z, at 8.
[204] *Id*.
[205] *Id*., at 14.
[206] Exhibit EE.
[207] *Id*.

current and committed resources, PRPA has enough capacity to maintain a 19.9% planning reserve margin through 2029.[208] PRPA began commercial operation of a 150 MW solar project in 2025,[209] plans to begin a 130 MW solar project in 2027, and is beginning processes to obtain additional dispatchable capacity.[210] PRPA has no resource adequacy issues now or forecasted upon the retirement of Craig Unit 1. As shown by its annual required filing with the Colorado Energy Office ("CEO"), its capacity well exceeds forecasted demand with a total accredited capacity of 885 MW and a native load forecast of 722 MW for 2026, leading to a planning reserve margin of 25.4%.[211] PRPA's General Manager and CEO has publicly stated that the utility does "not need the Craig 1 unit because it has already replaced the energy that came from it."[212]

c. FERC and RTO oversight ensures reliability at the regional level.

In addition to these extensive State processes developed under the States' sovereign authority, the Craig Unit 1 Owners are all overseen by a variety of authorities, acting under FERC's delegated authority. As noted above, the FPA places this authority with FERC and does not provide any authority for oversight of long-term resource planning to the Department in Section 202(c). The FERC, RTO, and State processes work together to ensure reliability, and the Renewed Order illegally intrudes on these processes without any reasonable basis.

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[208] *Id*.
[209] PRPA, *Solar Energy* (2026).
[210] Exhibit EE, at 178.
[211] PRPA, *Worksheet Certification Form* (Apr. 28, 2025).
[212] Exhibit RR (Powell, R., *1 coal plant open amid order* (Jan. 6, 2026)) at 3.

RTOs are well recognized for their grid reliability benefits. An RTO is the most comprehensive structure operating within the bulk power system, as it typically has "oversight of centralized unit commitment, economic dispatch, coordinating over a larger, multi-utility footprint and planning transmission system expansion."[213] The general benefits of being in an RTO are increasing as localized threats, such as extreme weather, become more common, which can affect supply while also increasing demand.[214] SPP's recent western expansion makes it the first RTO spanning two interconnections.[215]

States can elect to require their utilities to join RTOs and often do so due to their additional reliability benefits. Colorado requires all its transmission utilities to join an organized wholesale market on or before January 1, 2030, in part because the legislature found that the participation of utilities in RTOs and ISOs will assist in "ensuring the resilience of the electric grid and its resistance to both natural disasters and intentional attacks."[216] Accordingly, Tri-State and PRPA have joined SPP as of April 1, 2026, and now have capacity obligations under SPP's tariff. [217]

SPP's resource adequacy requirements complement the primary role of the states. SPP sets a base planning reserve margin that is determined by a probabilistic

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[213] Ahumada-Paras, M. et. al., *Grid Regionalization in the West: Reliability Benefits from Increased Cooperation in Electricity Markets and Operations*, at 1 (Stanford Climate & Energy Policy Program, Aug. 2024).
[214] Clean Energy Buyers Institute, *The Benefits of New Regional Transmission Planning Entities in the U.S. West and Southeast Region*, at 4 (Feb. 2023).
[215] SPP, *SPP And Member Utilities Successfully Complete Historic Western Expansion* (Apr. 2, 2026).
[216] § 40-5-108, Colo. Rev. Stat.
[217] SPP, *Open Access Transmission Tariff, Sixth Revised Volume No. 1* ("OATT"), Attachment AA (FERC e-Tariff, last viewed Apl. 27, 2026); *see also* SPP Transmittal Letter, FERC Dockets ER24-2184 and ER24-2185, at 50 (filed June 4, 2024).

loss of load expectation study, which compares resources availability to forecasted peak demand.[218] Each member of the RTO must meet the summer season and winter season resource adequacy requirement or pay for any deficient capacity.[219] After each summer and winter season, transmission providers are required to conduct an analysis to compare actual net peak demand versus the planning forecast, in order to evaluate the accuracy and consistency of the forecast.[220] Beginning January 1, 2027, entities joining in the SPP West balancing authority area must own or procure the capacity to meet the entity's seasonal non-coincident peak load plus SPP's planning reserve margin for each summer and winter season.[221] In the interim, the entities' current resource adequacy processes will apply.[222]

A Future Energy and Resource Needs Study ("FERNS") for SPP conducted by the Brattle Group found that across all five of the scenarios it ran, "resource adequacy and reliability are maintained through an hourly 5% operating reserve margin requirement during all system conditions, including the challenging weather and resource adequacy conditions captured in the [] proxy year."[223] Planning reserve margins are anticipated to significantly increase over time, and remain approximately 40% during the summer and 60% during the winter through the mid-2030s.[224] Importantly, Craig Unit 1's capacity was not factored into any of SPP's reliability

[218] SPP *OATT*, Att. AA § 4.
[219] *Id.* § 5.
[220] *Id.* § 12.
[221] SPP OATT, Att. AA; SPP, *see also* 195 FERC ¶ 61,015, P9 (Apr. 7, 2026).
[222] SPP Transmittal Letter, ER24-2184 & ER24-2185, at 56.
[223] The Brattle Group, *Future Energy & Resource Needs Study (FERNS)*, at 25 (Mar. 2025).
[224] *Id.*

assessments or considerations because the unit was expected to be retired by December 31, 2025. Thus, Craig Unit 1 is not needed for SPP to meet its reliability and resource adequacy needs.

Additionally, RTOs, including the SPP RTO, often act as balancing authorities and reliability coordinators. Reliability coordinators are the highest level of authority under NERC. They are responsible for the operation of the bulk electric system and have the operating tools, procedures, and authority to prevent or mitigate emergency operating situations.[225] Balancing authorities ensure that power system demand and supply are balanced, manage transfers of electricity and use economic dispatch to optimize the use of generating units and minimize real-time costs, and maintain operating conditions under NERC reliability standards.[226]

SPP is the reliability coordinator for Tri-State, PRPA, and Public Service.[227] SPP has been a reliability coordinator for over 20 years and has extensive operating criteria, outage coordination methodology, and emergency protocols from its operation of the eastern balancing authority.[228] SPP has a Reliability Plan that details how it monitors for and responds to an emergency.[229] Like all Reliability Coordinators, SPP has "a wide-area view, operating tools, processes and procedures to prevent or mitigate emergency operating situations in next day analysis and real-time conditions[]" and has the authority to act and instruct its members to take actions to

[225] NERC, *NERCipedia: Reliability Coordinator* (2024).
[226] Department, *How it Works: The Role of a Balancing Authority* (Apr. 17, 2023).
[227] SPP, *Western RC Services* (2026).
[228] SPP, *Operating Reliability* (2026).
[229] Exhibit HH (SPP, *SPP Reliability Plan* (Jun 2, 2025)).

preserve the integrity and reliability of the bulk electric system.[230] SPP is also now the balancing authority for Tri-State and PRPA.[231]

An energy emergency is defined by NERC, WECC, and SPP as a situation when a load serving entity has exhausted all options for obtaining capacity and can no longer provide its customers with expected energy requirements.[232] A reliability coordinator will initiate an energy emergency alert at their own request, upon the request of a balancing authority, or upon the request of a load serving entity.[233] Reliability Coordinators and balancing authorities make the decision to call or request the calling of an emergency pursuant to their emergency plans and operating procedures. SPP has not called an energy emergency alert, despite having the same (or likely more) information as the Department about the reliability of the grid in the areas served by Craig Unit 1. And even if SPP were to call any level of an energy emergency alert, that would not correlate to a need for the Department to issue a Section 202(c) order, due to the processes that SPP has in place to deal with such conditions.

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[230] *Id.,* at 6-7.
[231] SPP, *2026 RTOE SWPW Transition Plan — Market Participant* (Mar. 4, 2026); SPP, *Consolidated Balancing Authority*, SPP Portal (last viewed Apr. 27, 2026).
[232] WECC, *Standard EOP-002-2 - Capacity and Energy Emergencies* (2007); SPP, *Current Grid Conditions*, Markets & Operations (last viewed Apr. 27, 2026).
[233] *Id.* At an Energy Emergency Alert Level 1, a Balancing Authority will call on all available power supplies, regardless of economics, including from other grids, and enable demand-side resource deployments.# At an Energy Emergency Alert Level 2, a Balancing Authority will initiate demand response programs that shed load from large industrial customers that have contractually agreed to do so and will publicly appeal to customers to cut back on electricity consumption.# If the highest level of emergency, Energy Emergency Alert Level 3, is called, then Reliability Coordinators will conduct emergency operating procedures to increase transfer capabilities into the entity declaring the emergency. NERC has general emergency operating instructions that address the effects of emergencies by ensuring each transmission operator and Balancing Authority has developed plans to mitigate operating emergencies and those plans are implemented and coordinated within the reliability coordinator. Exhibit II (NERC, Emergency Operations).

Therefore, if an emergency did occur in the areas in the WECC-Rocky Mountain assessment area or SPP, there are extensive procedures in place for that emergency to be handled by the complex and comprehensive network of the utilities themselves, Reliability Coordinators, and balancing authorities without the Department overstepping and preemptively trying to solve an emergency that has not occurred, and is not predicted to occur in any relevant assessment. The Renewed Order states merely that there is an emergency in the WECC-Rocky Mountain assessment area because of a potential shortfall eight years from now. There is no evidence, and the Renewed Order cites none, that an emergency within the WECC-Rocky Mountain assessment area or SPP system could not be handled by SPP's existing procedures and the existing mix of resources available in the region upon Craig Unit 1's retirement.

iv. The Executive Orders cited in the Renewed Order are not evidence of an energy emergency.

The Renewed Order also relies on the Energy Emergency and Grid Reliability Executive Orders as evidence of an energy emergency, generally stating that the Energy Emergency and Grid Reliability Executive Orders underscore "the [ ] energy challenges facing the Nation due to growing resource adequacy concerns."[234] However, neither of these executive orders present evidence of an energy emergency in the WECC-Rocky Mountain assessment area or any other region of the country within the meaning of Section 202(c).[235]

[234] Exhibit TT, at 6.
[235] *See* 10 C.F.R. § 205.371 (2026) (defining emergency as a "specific inadequate power supply situation").

On January 20, 2025, President Trump issued Executive Order 14156, *Declaring a National Energy Emergency* ("Energy Emergency Executive Order").[236] Despite its title, the Energy Emergency Executive Order fails to describe any type of energy emergency. It generically claims "[t]he energy … generation capacity of the United States [is] far too inadequate to meet our Nation's needs," and the situation "will dramatically deteriorate in the near future…"[237] The Energy Emergency Executive Order also specifically calls out the Northeast and West Coast states, claiming those states' "dangerous" "policies jeopardize our Nation's core national defense and security needs, and devastate the prosperity of not only local residents but the entire United States population."[238] The Executive Order does not identify any specific policies or explain how they are jeopardizing grid reliability.

President Trump then issued Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, ("Grid Reliability Executive Order") on April 8, 2025.[239] The Grid Executive Order also claims that the country is "experiencing an unprecedented surge in electricity demand," generically pointing to expansions of data centers and increases in domestic manufacturing as demand drivers.[240] These vague statements on nationwide energy needs are not sufficiently specific to justify a Section 202(c) order.

[236] Exec. Order 14156, 90 Fed. Reg. 8433, 8434 (Jan. 20, 2025).
[237] *Id.,* at Sec. 1.
[238] *Id.*, at 8434.
[239] Exec. Order 14262, 90 Fed. Reg. 15521.
[240] *Id.*

Neither of these Executive Orders provide data or other evidence in support of their claims of inadequate nationwide generation, let alone evidence of inadequate generation in the areas served by Craig Unit 1 such that they could constitute the evidence required to support the Renewed Order. The Energy Emergency Executive Order refers to a deterioration "in the near future,"[241] while the Grid Reliability Executive Order offers no projection for the timing or location of the increased demand it speculates.[242] This does not satisfy Section 202(c)'s requirements, discussed above in Section V.A., that an emergency must be specific and imminent.

Importantly, the facts contradict the vague assertions of an energy emergency contained in the Executive Orders. For example, America's domestic energy production is at an all-time high given its diverse mix of both fossil and non-fossil fuel resources. The United States is producing record quantities of oil and natural gas,[243] and has been a net energy exporter since 2019.[244]

Similarly, the Energy Emergency Executive Order's assertion that the United States has an "inadequate and intermittent energy supply, and an increasingly unreliable grid" is unsupported by the facts.[245] NERC reports that the bulk power system is resilient, and that the largest challenge for reliability is extreme weather induced by climate change.[246] Renewable energy resources both mitigate climate

[241] Exec. Order 14156 at 8433.
[242] Exec. Order 14262.
[243] U.S. Energy Information Admin. ("EIA"), *Short-Term Energy Outlook Data Browser* (Jan. 13, 2026).
[244] EIA, *In-Brief Analysis: The United States was the world's largest liquified natural gas exporter in 2023* (Apr. 1, 2024); EIA, *U.S. Exports of Crude Oil* (Dec. 31, 2025); EIA, *U.S. Energy Facts Explained* (July 15, 2024).
[245] Exec. Order 14156 at 8433.
[246] NERC, *2024 State of Reliability* (June 2024), at 5.

change and improve the overall reliability and affordability of the United States' energy supply by tempering the impact of international commodity price swings on natural gas prices and reducing grid operators' reliance on interruptible natural gas deliveries.[247] Solar and wind generated more than 15% of all electricity and 8% of all energy consumed in the United States in 2024.[248]

Next, the Renewed Order relies in part on "the expansion of artificial intelligence data centers" referenced in the Grid Reliability Executive Order and other projected demand growth noted in the Department Resource Adequacy Report to support its finding of an emergency.[249] But the Order's discussion of data center load growth is both irrelevant and unsubstantiated.

Neither the Grid Reliability Executive Order nor the Renewed Order specify any timeframe for when the increased energy demand from data centers is expected to occur. Section 202(c) does not give the Department the authority to retain generation units for possible conditions that may arise at some indeterminate time in the future. Authority to address long-term threats to resource adequacy rests with the states and FERC and its designated entities, all of which are aware of and extensively planning for this potential load growth. The Renewed Order does not cite any evidence that data center load growth will occur in the areas served by Craig Unit 1 during the 90 day period of the Renewed Order. As demonstrated in their respective resource plans,

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[247] FERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 16, 2021), at 172 ("Natural gas fuel supply issues alone caused 27.3[%] of the generating unit outages" during Winter Storm Uri).
[248] EIA, *Short-Term Energy Outlook* (Feb. 11, 2025), *see* the 2024 data; EIA, *December 2025 Monthly Energy Review* (Dec. 23, 2025).
[249] Exhibit TT, at 6.

the Craig Unit 1 owners are not anticipating any new data centers or other large loads over 50 MW to come online in their service territory in the next 90 days.[250] And where Colorado utilities anticipate data centers coming online in the next five years, they are planning for that additional load through their established resource planning processes.

D. The Renewed Order is arbitrary and capricious because it requires generation that does not best meet the claimed emergency.

Even if there were an emergency within the meaning of the FPA, which there is not, Section 202(c)(1) requires the Department to impose requirements that "will best meet the emergency and serve the public interest."[251] The Department has failed to demonstrate that delaying the retirement of Craig Unit 1 satisfies this standard, and the Renewed Order is therefore arbitrary and capricious. The Renewed Order's operating instructions do not best meet the emergency or serve the public interest. Preventing the retirement of Craig Unit 1 cannot meet the Department's claimed emergency, and even if it could, it would not be the best means to do so.

i. Directing SPP to employ economic dispatch of Craig Unit 1 is vague and does not best meet the alleged emergency.

The Renewed Order changes the operating directions for Craig Unit 1 from the Original Order. In the Original Order, Tri-State and the co-owners were instructed to "take all measures necessary to ensure that Craig Unit 1 was available to operate at the direction of either. . . . [WACM] in its role as Balancing Authority or [SPP] West in

[250] *See supra,* Section V.C.iii.
[251] 16 U.S.C. § 824a(c)(1).

its role as the Reliability Coordinator[.]"[252] The Renewed Order kept these instructions for the first day of the Renewed Order, March 31, 2026, and then changed the instructions to direct "SPP [ ] to take every step to employ economic dispatch of Craig Unit 1[.]"[253] The Department provided no explanation for the change in operating instructions or how that change would result in best meeting their alleged emergency. Neither instruction best meets the alleged emergency or serves the public interest. Regarding the illegality of the operating instructions for March 31, 2026, the State of Colorado incorporates its arguments from its Original Request of the Original Order.[254]

First, the instruction for SPP to employ economic dispatch of Craig Unit 1 is vague. The Renewed Order does not define "economic dispatch" or specify any other parameters for how it intends SPP to dispatch the Unit. The Renewed Order also states that "Craig Unit 1 shall not be considered a capacity resource[,]"[255] but SPP does not use the term "capacity resource" in its procedures and operations, making it unclear what the Renewed Order is referring to.

In addition, the Renewed Order does not reconcile the fact that operating a unit using economic dispatch is inherently at odds with that unit being operated only in an emergency. The Energy Policy Act defines economic dispatch as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission

[252] Exhibit A, at 4.
[253] Exhibit TT, at 8.
[254] Exhibit CCC.
[255] Exhibit TT, at 8.

facilities."[256] Economic dispatch is standard procedure for grid operators, including SPP.[257] Emergencies necessarily require unique grid operation, which is why generation units may be dispatched to provide "Out-of-Merit Energy" during an emergency. When SPP needs to resolve a reliability issue the market system cannot solve, or an emergency condition, it will dispatch "Out-of-Merit Energy" so that a resource can produce what is necessary to address a constraint.[258] This necessarily means that the resources may be operated out of economic order.[259] The dispatch directive typically specifies the MW level a resource should produce at until the constraint can be resolved through security constrained economic dispatch.[260] Operating a unit pursuant to economic dispatch is necessarily inconsistent with operating a unit to address an energy emergency. If a unit is necessary to address an emergency, it would need to be dispatched regardless of price, which does not conform to economic dispatch. The Renewed Order fails to grapple with this conflict.

Further, the Department makes no attempt to demonstrate that operating Craig Unit 1 at economic dispatch is in the public interest. Because the Renewed Order's operating instructions are vague and not aimed at meeting a specific emergency, the Department does not ensure that Craig Unit 1 only operates when necessary for an emergency, thereby unnecessarily increasing emissions and costs to

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[256] 42 U.S.C. § 16432(b).
[257] SPP, *Integrated Systems Scenario Detail: OOME (Out-of-Merit Energy Dispatch),* (rev. 3.0 Apr. 24, 2013)
[258] *Id;* SPP, *Integrated Marketplace Protocols*, Section 4.4.2.5 (Apr. 17, 2026).
[259] *See* Kim Farris, *Assorted Charge Types - SUG Presentation*, slide 12 (Feb. 14, 2012).
[260] SPP, OOME Scenario (rev. 3.0).

customers, and rendering the Renewed Order an improper exercise of the Department's emergency authority.

The problems with the Renewed Order's operating instructions were demonstrated soon after the Renewed Order was issued. SPP called a Resource Advisory on April 7, 2026, effective from April 8th until April 24th.[261] SPP Resource Advisories are still considered normal operating conditions, and are not considered emergency conditions.[262] According to SPP, "Resource Advisories are still considered Normal Operating Conditions, and do not require the public to conserve energy or take any action, but are issued to raise awareness of potential threats to reliability among entities responsible for operating transmission and generation facilities."[263]

SPP called the April 7th resource advisory "due to load uncertainty, increased potential for low output from wind and other variable energy resources (*also known as low VER forecast) leading into peak hours, and potential for resource outages."[264] In addition, Colorado understands that there were several planned maintenance outages occurring in the areas where SPP had just set up its new market on April 1, 2026. And once a Resource Advisory is called, all units marked as "reliability" are called up, regardless of whether those units are actually needed. Therefore, the Department's vague and improper operating instructions resulted in SPP calling on Craig Unit 1 for a reliability need that did not rise to the level of an emergency and thus was outside the scope of the Department's authority under Section 202(c).

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[261] Exhibit FFF (SPP, *Current Gird Conditions* (Apr. 20, 2026)).
[262] Exhibit GGG (SPP, *Current Gird Conditions* (Apr. 7, 2026)); SPP, *Current Grid Conditions*.
[263] *Id.*
[264] *Id.*

ii. Preventing Craig Unit 1's retirement does not "meet the emergency."

It is unclear how preventing Craig Unit 1's retirement could meet the emergency that the Department alleges. The nature and extent of the claimed emergency are unclear. And even if there were a capacity shortfall in any of the states served by Craig Unit 1 or the WECC-Rocky Mountain assessment area, the Renewed Order does not provide a reasoned basis for its conclusion that the continued operation of Craig Unit 1 is the best or even a viable means of alleviating the purported shortfall.

The Department cannot demonstrate that delaying Craig Unit 1's retirement meets the emergency because the Renewed Order's emergency declaration is unclear and unsupported by the record. The Renewed Order declares there is an emergency in the WECC-Rocky Mountain assessment area.[265] However, the Renewed Order goes on to remedy this emergency by directing SPP to employ economic dispatch of Craig Unit 1. Since Craig Unit 1 has been a part of the SPP RTO for all but the first day of the duration of this Renewed Order, Craig Unit 1 can only best meet an emergency in the SPP RTO area. The SPP RTO does not cover all of the WECC-Rocky Mountain assessment area.[266] The Renewed Order's remedy does not match its declared emergency.

The Renewed Order also fails to demonstrate that there is a resource shortfall imminent and specific enough to require the continued operation of any particular

[265] Exhibit TT, at 4.
[266] Exhibit WW, at 8; SPP, *SPP and Member Utilities Successfully Complete Historic Western Expansion* (Apl. 2, 2026).

resource. Thus, it is unclear how Craig Unit 1 could meet the Department's alleged emergency, regardless of how the Renewed Order's emergency determination is interpreted.

iii. Delaying the retirement of Craig Unit 1 does not "best" meet the Department's purported emergency.

Even if delaying the retirement of Craig Unit 1 could meet the non-existent alleged emergency in the WECC-Rocky Mountain assessment area, the Department has provided no explanation of how that resource would best meet such an emergency. "Best" means "that which is 'most advantageous'" or "excelling all others."[267]

The Renewed Order, and the materials upon which it relies, offer no facts that would support a determination that Craig Unit 1 is the "most advantageous" way to address the alleged emergency. Even if the Renewed Order had successfully described an emergency scenario for the regions served by Craig Unit 1 or the WECC-Rocky Mountain assessment area, the Department has not provided any specific evidence or reasoning explaining why requiring Craig Unit 1 to be available to operate is the most advantageous way to meet the scenario. Other orders issued by the Department in 2025 suffer from the same flaw, as the Congressional Research Service identified in July 2025, noting that Orders issued to the Campbell and Eddystone units have not "identified reliability risks specifically associated with the retirement of the power plants in question at the time they approved those retirements."[268] In this respect,

[267] *Entergy Corp.*, 556 U.S. at 218 (quoting Webster's New International Dictionary 258 (2d ed.1953)); *Best*, Merriam-Webster Dictionary (Jan. 25, 2026).
[268] Exhibit T (Congressional Research Service, Federal Power Act: The Department of Energy's Emergency Authority (June 12, 2025)), at 5-6.

the Department's exercise of its emergency authority in 2025 departs markedly from past uses of Section 202(c) and from the Department's regulations implementing Section 202(c). Those regulations specify that: "[a]ctions under this authority are envisioned as meeting a specific inadequate power supply situation."[269] The Department's 2026 Section 202(c) orders have not remedied this deficiency.

The definition of "best" includes "excelling all others," which requires a comparative judgment that there are no better alternatives. This means the Department must consider alternatives and choose the alternative that is most advantageous to meet the emergency the Department has identified. The Department need not consider every conceivable alternative, but it must consider alternatives within the ambit of the existing policy as well as alternatives which are significant and viable or obvious.[270]

The Department's regulations specify information the Department must consider in deciding how to best address an emergency in a Section 202(c) order. This includes conservation or load reduction actions, efforts to obtain additional power through voluntary means, available imports, demand response, and behind the meter generation resources.[271] The Renewed Order considers none of these alternatives. Nor does it explain whether less burdensome measures were considered or exhausted before invoking the Department's emergency authority. Indeed, the Renewed Order

[269] 10 C.F.R. § 205.371.
[270] *See Dep't of Homeland Sec.*, 591 U.S. at 30 (failure to consider alternative was arbitrary and capricious); *see also Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 51 (must consider alternatives "within the ambit of the existing [standard]").
[271] 10 C.F.R. § 205.373(g)-(h). While this information is specifically required when a utility applies for a 202(c) order, it illustrates the types of information that is relevant to an alternatives analysis.

never quantifies the extent of the emergency it purports to identify within Colorado or any of the states served by Craig Unit 1, making a meaningful alternatives analysis impossible. To satisfy Section 202(c)(1)'s requirement that the ordered solution best meet the emergency, the Renewed Order must address why the resources that make up the excess planned reserve margins could not meet the alleged emergency.

The Craig Unit 1 Owners chose to retire Craig Unit 1 for economic reasons.[272] And because the unit was set to retire, Craig Unit 1 has not had major maintenance since 2019;[273] it is also 45-years-old, beyond the typical economic design life of a coal burning generator and near the end of a generator's typical operational life.[274] Keeping Craig Unit 1 running will be more costly now because of the deferred maintenance costs in addition to costs for fuel and continued operations.[275] Colorado's understanding is that, since the issuance of the Original Order, Tri-State has had to expend costs on maintenance and staffing.[276] These costs are currently unknown but expected to be significant, and will continue needlessly as long as the Department continues to prevent Craig Unit 1's retirement. There will also be additional costs every time SPP dispatches Craig Unit 1. Tri-State and PRPA have already stated that the costs of compliance with the orders "fall directly on their members and customers" and that the Original Order "impose[d] additional costs to

[272] Tri-State, *Craig Station owners, regulators and environmental groups reach agreement on proposed revisions to Colorado regional haze plan* (Sept. 1, 2016).
[273] Exhibit B, ¶ 34.
[274] Grid Strategies, *The Economic Cost of a DOE Mandate for the Craig Unit 1 Coal-Burning Generator to Continue Operating* at 2 (Dec. 2025).
[275] Exhibit D, ¶¶ 13-15.
[276] *See* Exhibit B, ¶ 34.

Tri-State's membership and the communities served by Platte River."[277] In their Request for Rehearing of the Original Order, Tri-State and PRPA asserted that keeping Craig Unit 1 is not a best option because their members and customers will have to pay the costs associated with Craig Unit 1 even though "neither Tri-State nor Platte River are experiencing these shortages and not all the members and customers served by Tri-State and Platte River are located in the region identified by the Order."[278]

Complicating the fuel issue, Tri-State did not plan on continuing to acquire or use coal for Craig Unit 1 due to its scheduled retirement. Craig Station is supplied with coal from the Colowyo Mine, which ceased coal production at the end of 2025.[279] Tri-State has already contracted with Kiewit Mining Group, Inc., to reclaim the mine following its closure, and reclamation activities were scheduled to begin on or about January 1, 2026.[280] Moreover, the Colowyo mine has been permanently closed and its operator has transitioned to reclamation activities.[281] It is Colorado's understanding that before the mine's closure, Tri-State obtained enough coal to fuel Craig Units 2 and 3 through their planned retirement dates in 2028 but did not expect to need coal to power Craig Unit 1. If Tri-State needs to use coal acquired to fuel Craig Units 2 and 3 to unexpectedly fuel Craig Unit 1, it will likely not have enough supply to also fuel

[277] Exhibit UU, at 2
[278] *Id.*, at 5.
[279] Jaffe, M., *Tri-State expects federal order to keep coal-fired power plant in northwestern Colorado running* (Nov. 14, 2025).
[280] Tri-State, *Colowyo Mine to conclude coal production in 2025, transitioning to full reclamation* (Aug. 7, 2025).
[281] Weiser, C., *Colowyo coal mine near Craig lays off 133 workers as mine closes* (Nov. 26, 2025); WarnTracker.com, *1 WARN Layoff Notice for ColoWho Coal Company LP on Nov 2025* (2025).

the other units. Tri-State would then have to buy more expensive, and possibly dirtier, coal from another source.[282]

In addition, coal generation is generally more costly than other generation resources.[283] The inefficiency of running a coal plant makes it uneconomic and is the main reason that Craig Unit 1 (and eventually, the rest of Craig Station) was slated for retirement. In fact, the CoPUC approved coal fired generating unit retirements to be replaced with lower cost wind, solar, and use of gas as a capacity resource because wind and solar were the lowest cost resources available and it was cheaper to add new renewables, storage and gas generation to the system and retire coal units.[284]

Coal generation also does not guarantee reliability, which further emphasizes that Craig Unit 1 does not best meet any emergency. For example, Unit 18 of the R.M. Schahfer Generating Station has been in a forced outage since July, after experiencing another forced outage from February 16, 2025 to June 23, 2025.[285] As of March 24, 2026, the unit was still in a forced outage.[286] Yet, despite the unit being

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[282] *See* Exhibit B, ¶ 32.

[283] Weiser, C., *Colowyo coal mine near Craig lays off 133 workers as mine closes* (Nov. 26, 2025). A report by Grid Strategies found that ratepayer costs could exceed $3 billion per year if the Department mandates that all of the fossil power plants scheduled to retire between the time the report was published in August 2025 and the end of 2028 remain open. Grid Strategies asserts that the Department is ignoring the careful planning of states and utilities and "overriding cost-minimizing retirement decisions that have been made by state utility regulators and merchant power plant owners based on extensive information regarding the cost, performance, condition, and need for each plant." *see also* Grid Strategies, LLC, *The Cost of Federal Mandates to Retain Fossil-Burning Power Plants* (Aug. 2025) at 3; Exhibit O, which cost a staggering $29 million over the first 38 days; Solomon, M., et al., *Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment* (Jan. 2023), at 1-2 (a report by Energy Innovation found that "99[%] of all coal-fired plants in the U.S. are more expensive to operate on a forward looking basis than the all-in cost of renewable energy projects," and that "all but one of the country's 210 coal plants are more expensive to operate than either new wind or solar.").

[284] CoPUC, Decision No. C18-0761, issued on September 10, 2018, in Proceeding No. 16A-0396E, ¶ 103.

[285] *Id.*

[286] IURC STATE OF INDIANA, *3/24 – Public Meeting* (YouTube, Mar. 24, 2026), at 3:16:22.

offline, the Department issued an order requiring it to remain available on December 23, 2025.[287] Additionally, the newest large coal-fired plant in the U.S. suffered an outage in fall of 2025 and will now be offline until March 2027.[288] This is the second time that plant has been unable to operate for a year or more.

These facts illustrate a clear pattern: coal is not the first choice when considering reliable, affordable generation. And the Renewed Order contains no facts (either in its text or in the cited materials) that supports any determination that ordering continued availability and operation of an off-line coal unit is a reasonable response to a perceived emergency, much less "best meets" such an emergency. This is especially concerning given that Craig Unit 1's continued operation will also prevent the use of solar electricity generated by a newly added solar Axial Basin generating facility in Moffat County due to limited transmission capacity.[289] The Department does not explain how use of Craig Unit 1 is the best means to address an alleged energy shortfall when its use curtails use of other sources of power.

Given the cost of operating Craig Unit 1 and questions of reliability surrounding coal plants generally, the Department has failed to demonstrate that Craig Unit 1's continued operation "best meets the emergency" and therefore the Renewed Order is arbitrary and capricious.

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[287] Exhibit S.
[288] Institute for Energy Economics and Financial Analysis, *Newest big U.S. coal-plant offline until 2027* (Oct. 7, 2025); Tri-State, *Tri-State makes Craig Generating Station Unit 1 available to operate in compliance with DOE emergency order* (Jan. 23, 2026).
[289] Exhibit UU, at 7.

E. The Renewed Order's Terms Fail to Comply with Statutory Requirements.

The Renewed Order fails to comply with Sections 202(c)(2) and 202(c)(4)(b) of the FPA, and Section 103(b) of the Department Organization Act.

i. The Renewed Order violates Section 202(c)(2) because it fails to ensure consistency with federal and State environmental laws and fails to minimize adverse environmental impacts.

Section 202(c)(2) imposes mandatory duties on the Department if a Section 202(c) order "may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation[.]"[290] The Renewed Order explicitly conflicts with the environmental laws and regulations that apply to the Craig Station Unit 1 Owners, and may also result in additional conflicts with environmental laws and regulations that apply to the State of Colorado.[291] The Department failed to comply with these requirements, rendering the Renewed Order illegal.

a. The Renewed Order directly conflicts with federal and State laws requiring Craig Unit 1 to close by December 31, 2025.

The Renewed Order directly conflicts with federal and State environmental laws and regulations that require the closure of Craig Unit 1 by December 31, 2025. These include Air Commission's Regulation Number 23, Colorado's Regional Haze SIP adopted pursuant to the federal Clean Air Act, and Tri-State's operating permit issued pursuant to Title V of the federal Clean Air Act.[292]

The Air Commission (with the Craig Unit 1 owners' consent) adopted the December 31, 2025 closure date into State law through Regulation Number 23, which

[290] 16 U.S.C. § 824a(c)(2) (emphasis added).
[291] *See* Exhibit B.
[292] *Id.*

regulates regional haze.[293] The EPA then approved this closure date into federal law when it approved Colorado's Regional Haze SIP in 2018.[294] In addition, Craig Unit 1 is a major source of air pollution[295] and therefore requires, and operates under, an operating permit issued pursuant to Title V of the federal Clean Air Act.[296] A Title V permit includes emissions limits, operational requirements, reporting obligations, and other requirements to ensure the safe and environmentally responsible operation of major sources. Condition 1.10 of Craig Unit 1's operating permit specifies that the Unit must close on or before December 31, 2025.[297]

In addition, the Colorado Legislature directed the Air Commission to adopt rules to help meet statewide statutory GHG reduction goals.[298] The Renewed Order's direction for continued availability and operation of Craig Unit 1 may restrict Colorado's ability to meet these statutory goals.

Thus, by ordering the Craig Station owners to return Craig Unit 1 to service and to be available to operate beyond the December 31, 2025 closure date, the Renewed Order directs the owners to violate both State and federal law, and is subject to the requirements of Section 202(c)(2).

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[293] *See* 5 Colo. Code Reg. § 1001-27:A.IV.D.
[294] Air Plan Disapproval; Colorado; Regional Haze Plan for the Second Implementation Period, 91 Fed. Reg. 3048, 3049, fn. 9 (Jan. 26, 2026); EPA, *EPA Approved Statues and Regulations in the Colorado SIP* (Jan. 6, 2026); 83 Fed. Reg. 31332 (July 5, 2018).
[295] Craig Station is a major source and Craig Unit 1, by volume of pollution emitted, is itself a major source. Exhibit B, ¶ 28; Exhibit KK (Division, *Operating Permit No. 96OPMF155* (July 1, 2021));
[296] *See* Exhibit KK; 42 U.S.C. § 7661a(a).
[297] *See* Exhibit KK, at 25.
[298] *See* § 25-7-105(1)(e), Colo. Rev. Stat.; Exhibit B, ¶ 30; § 25-7-102(2)(g), Colo. Rev. Stat.

b. The Renewed Order does not comply with Section 202(c)(2).

Because the Renewed Order conflicts with State and federal environmental laws, the Department was required to ensure that the Renewed Order: 1) " requires generation, delivery, interchange, or transmission of electric energy *only* during hours necessary to meet the emergency and serve the public interest," 2) "to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation," and 3) "minimizes any adverse environmental impacts."[299] The Department's Renewed Order contains no conditions or instructions that meet these requirements.

First, by referring to the "hours" necessary to meet the emergency, Congress placed a high burden on the Department to demonstrate that the remedy provided in a Section 202(c) order is narrowly tailored to the specifics of the emergency that the order is designed to address. Even if the Department had identified a true emergency (which it has not), the FPA authorizes the Department to compel generation only when an emergency shortage of electric energy would occur absent operation of Craig Unit 1 specifically.[300] The Department's Renewed Order merely states that "SPP is directed to take every step to employ economic dispatch of Craig Unit 1 to minimize costs to ratepayers."[301] The Renewed Order's terms fail to require operation "only during the hours necessary to meet the emergency" described by the Renewed Order

[299] 16 U.S.C § 824a(c)(2) (emphasis added).
[300] *Id.*; *see, e.g.*, Department, Order No. 202-17-4, *Summary of Findings* (Sept. 14, 2017), at 9 ("authorizing operation of" units subject to emergency order "only when called upon . . . for reliability purposes," according to "dispatch methodology" approved by Department.).
[301] Exhibit TT, ¶ B.

and violates Section 202(c)(2) because the Renewed Order does not establish any limited hours for SPP to follow when dispatching Craig Unit 1.

The Renewed Order does not define economic dispatch or specify how it intends SPP to dispatch Craig Unit 1. By leaving the dispatch of Craig Unit 1 entirely in the hands of SPP, the Department is failing to properly limit operation as required by Section 202(c). Without a clearly defined emergency, SPP has no standards to determine under what circumstances they should require the continued operation of Craig Unit 1. The premise for such continued operation is the energy "emergency" articulated in the Renewed Order, but it is impossible to know what conditions require Craig Unit 1 to operate by reading the Renewed Order.[302] Orders issued by the Department prior to 2025 demonstrate that the Department is capable of including appropriate limiting conditions in Section 202(c) orders. For example, in 2022, the Department issued an order in response to periods of extreme heat, drought conditions, and threat of wildfires that were expected to occur over several days and threaten the reliable operation of the bulk electric power system in California. That order directed the Balancing Authority of Northern California to dispatch specific units only "under the following conditions: the issuance and continuance of an Energy Emergency Alert Level[ ] 2 condition or greater between the hours of 14:00 Pacific Time and 22:00 Pacific Time after exhausting all reasonably and practically available

[302] Indeed, the Order contains confusing and contradictory instructions regarding the unit's operations, stating both that "Craig Unit 1 shall not be considered a capacity resource" and that its "continuous operation" is required. Exhibit A, at 1, ¶ G. Presumably, this means that the unit may only be called up by WAPA or SPP when there is an actual supply shortage that existing resources cannot meet. But if that is the intent, it is not clear from the face of the Order.

resources."[303] Although Section 202(c)(2) requires the Department to include limiting conditions in the Renewed Order as well, it chose not to, and that choice is contrary to law.

Second, Section 202(c)(2) requires that where an order may result in a conflict with environmental law or regulation, it must "to the maximum extent practicable, [be] consistent with any applicable Federal, State or local environmental laws." The Renewed Order contains no analysis of the plant's environmental obligations and no operational criteria established to minimize impacts. The Renewed Order merely states that "operations of Craig Unit 1 must comply with applicable environmental requirements . . . . to the maximum extent feasible while operating consistent with the emergency conditions."[304]

There are numerous environmental requirements that are affected by the continued operation of the Craig Unit 1 facility, but the Department failed to identify mechanisms to allow Craig Unit 1 to remain available or operate while minimizing conflicts with these requirements. As discussed further in Section V.F.iii., the Department also did not consult with the State of Colorado, including its environmental regulators, who could have advised on ways to minimize impacts.[305]

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[303] Department, Order No. 202-22-2 (Sept. 4, 2002) at 4; *see also Letter from Kevin Kolevar, Director, Office of Electricity Delivery and Energy Reliability to Robert Driscoll, CEO, Mirant Mid-Atlantic, LLC* (May 31, 2007) (Letter from the Department describing the emissions limitations that a utility should follow when complying with a 202(c) order.); Department, Order No. 202-17-1 (Apr. 14, 2017) (202(c) Order from the Department instructing SPP to adopt a temporary operating guide and comply with additional operating requirements set out in an EPA compliance order).

[304] Exhibit TT, ¶ D.

[305] Exhibit B, ¶¶ 10, 33-35; *see also* Section 103 of the Department of Energy Organization Act, 42 U.S.C. § 7113 (requiring the Department to give due consideration to the needs of states when proposing any action that conflicts with a state energy plan, and to attempt to resolve conflicts through consultations with appropriate state officials). The Order plainly conflicts with Tri-State's

The Renewed Order does not reference or discuss the applicable environmental laws and regulations impacted by the Renewed Order, revealing the Department's failure to analyze these requirements to ensure compliance with environmental standards.

In particular, the Renewed Order fails to reflect any consideration of interactions with the federal Clean Air Act Regional Haze program[306] or National Ambient Air Quality Standards ("NAAQS") attainment and permitting programs. The Regional Haze program requires states to reduce emissions of NOx, SO_2, and PM from sources that affect Class I federally protected areas.[307] States must conduct detailed and expensive analyses, and based on the results of those analyses, impose federally enforceable controls and emission limits upon the largest and most impactful sources of haze pollutants.[308] The federal Clean Air Act, through the NAAQS attainment and permitting programs, also directs states to achieve and maintain air quality standards for certain pollutants, including NOx, SO_2, and PM.[309] The Department does not appear to have conducted any analysis of the impact keeping Craig Unit 1 operational may have on sources' and Colorado's ability to comply with either of these programs. The Renewed Order gives no guidance as to whether it creates conflicts with either of these requirements and, if it does, how to navigate them.

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decision-making process, the CoPUC's approved ERPs, the EPA-approved Regional Haze SIP, and Air Commission's Regulation Number 23.

[306] EPA recently disapproved Colorado's Regional Haze Plan for Round 2 (which does not involve Craig Unit 1) by, in part, pointing to this Order. 91 Fed. Reg. at 3049, fn. 9 (Jan. 26, 2026). While Colorado maintains that EPA's action was improper, and that its Regional Haze SIP currently meets federal requirements, it does reveal that EPA considers Craig Unit 1 relevant to Colorado's compliance with Regional Haze requirements now and in the future. The federal government must, but fails to, take a consistent position in the Regional Haze SIP disapproval and the Order as it relates to Craig Unit 1.

[307] *See* 42 U.S.C. §§ 7491, 7492; *see also* implementing regulations at 40 C.F.R. § 51.300-309.

[308] *Id*.

[309] *See, e.g.,* 42 U.S.C. §§ 7409, 7410.

Accordingly, the Renewed Order violates the Department's statutory obligation to "ensure" the maximum feasible compliance with applicable environmental standards.[310] This obligation requires the Department to offer some discrete guidance as to the unit's operations, rather than merely parroting the statutory text. This lack of detail also makes it impossible for Colorado's environmental regulators to know what operational activities are excused from environmental compliance by the Renewed Order, increasing the complexity and burdens associated with any state enforcement actions.

Third, Section 202(c)(2) requires the Department to minimize the adverse environmental impacts of the Renewed Order, which the Renewed Order fails to do. This mandate is textually and substantively distinct from the Department's (also unfulfilled) obligation to ensure maximum practicable compliance with environmental standards. By failing to include a sufficient or legal description of the purported emergency, this Renewed Order authorizes Craig Unit 1 to generate electricity and pollute beyond any emergency needs, thereby increasing the environmental impacts that, by law, the Renewed Order must minimize. When Craig Unit 1 operates, it emits NOx, SO_2, fine PM, GHG emissions, HAPs, and other harmful pollutants.[311] The Renewed Order includes no measures to mitigate impacts when compliance with environmental standards proves impracticable, even though those types of measures have been routinely included in past orders.[312] At a minimum, the statute requires the

[310] 16 U.S.C. § 824a(c)(2) (emphasis added).
[311] Exhibit B, ¶ 14.
[312] *See, e.g.*, Department, Order No. 202-17-4 (Sept. 14, 2017) at 2 (permitting non-compliant operation only during specified hours, and requiring exhaustion of "all reasonably and practicably

Department to include sufficiently detailed reporting obligations to ascertain what impacts result from emergency operations; without such reporting, the Department has no ability to "ensure" that adverse impacts are minimized.[313] The Renewed Order here instead merely requires "such additional information" as the Department, in the future, may (or may not) "request[] . . . from time to time."[314] That possibility of future, unspecified information gathering cannot satisfy the statute's demand that the Department "ensure" that its Renewed Order minimizes environmental impacts.[315]

Similarly, the Renewed Order does not address or assess mechanisms to minimize the pollution from Craig Unit 1 associated with its operation in response to the Renewed Order. It also does not address or assess the environmental impacts associated with the acquisition and transport of additional coal that may be necessary to facilitate Unit 1's operation, and contains no limitations on the type of coal that may be used so as to minimize the impacts of any new emissions. Not all coal is inherently compatible with the units at the Craig Station, and depending on where new coal is sourced from, there could be significant emissions and costs associated with the distances required to import that coal.[316] Nor are these impacts addressed by

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available resources," including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions); Department, Order No. 202-22-4 (Dec. 12, 2022) (requiring "reasonable measures to inform affected communities" of non-compliant operations).

[313] *See, e.g.,* Department, Order No. 202-24-1 (Oct. 13, 2024) at 4-5 (requiring detailed data on emissions of pollutants).

[314] Exhibit TT, ¶ E.

[315] 16 U.S.C. § 824a(c)(2).

[316] Exhibit B, ¶¶ 33-34.

the Department's cursory instruction to Tri-State to comply with applicable environmental requirements "to the maximum extent feasible."[317] Because the Department made no attempt to address the requirements of Section 202(c)(2), the Renewed Order is unlawful.

ii. The Renewed Order violates Section 202(c)(4)(B) because the Department failed to consult with the primary federal agency with expertise in the relevant environmental interests.

Finally, the Renewed Order provides no indication that the Department has, as required by Section 202(c)(4)(B), "consult[ed] with the primary Federal agency with expertise in the environmental interest protected" by any laws with which the renewed or re-issued order may conflict.[318] Nor does the Renewed Order include any conditions such federal agency "determines necessary to minimize any adverse environmental impacts to the extent practicable" or a public explanation of the Department's determination that such conditions "would prevent the order from adequately addressing the emergency."[319]

The Renewed Order serves as a renewal of the Original Order on the claimed basis that "[t]he emergency conditions that necessitated the issuance of [the Original Order] continue."[320] As stated above, the Renewed Order conflicts with several federal and State environmental laws.[321] The EPA is the federal agency with expertise and authority over federal air quality regulations and approved Craig Unit 1's

[317] Exhibit TT, ¶ D.
[318] *See* 16 U.S.C. § 824a(c)(4)(B).
[319] *See id.*
[320] Exhibit TT, at 4.
[321] *See supra*, Section E.ii.a.

retirement date, Colorado's Regional Haze SIP, and Craig Stations' Title V Permit, making them federally enforceable. Therefore, the Department was required to consult with, at a minimum, the EPA prior to issuing the Renewed Order.

The Renewed Order makes no mention of this consultation requirement and provides no evidence of consultation with the primary federal agency, as the Department has in other Section 202(c) orders.[322] If the Department has failed to consult and procure any required conditions from the relevant federal agency, it has violated the statute. If it has received and declined conditions but refused to disclose them or provide any explanation of why the Department believes such conditions would prevent the order from adequately addressing the claimed emergency, that too violates the statute.

For these reasons, the Renewed Order fails to comply with the Department's obligations under Section 202(c)(2) and should be withdrawn.

iii. The Renewed Order violates Section 103 of the Department Organization Act because the Department failed to consult with the appropriate Colorado officials.

The Renewed Order violates Section 103 of the Department Organization Act, which requires:

> Whenever any proposed action by the Department conflicts with the energy plan of any State, the Department shall give due consideration to the needs of such State, and where

[322] *See, e.g.*, Exhibit U, at 8 ("Pursuant to [S]ection 202(c)(4)(B) of the FPA, the Department has consulted with the primary [f]ederal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order."); Exhibit PP, at 8 ("Pursuant to [S]ection 202(c)(4)(B) of the FPA, the Department has consulted with the primary [f]ederal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.").

> practicable shall attempt to resolve such conflict through consultations with appropriate State officials.[323]

The Department has acknowledged that Section 103 of the Department Organization Act is applicable to the Department in this situation. The Department argued in the Campbell case that the provision did not apply to the Original Campbell Order because consultation is not practicable in an emergency situation.[324] However, the Department has now had 90 days since the issuance of the Original Order to comply with Section 103 of the Department Organization Act, and it has failed to do so.

The Renewed Order conflicts with Colorado's statewide GHG pollution reduction targets[325] and interferes with Tri-State's plan to reduce GHG emissions 80 percent by 2030,[326] as reflected in the CoPUC's approval of Tri-State's ERP, which included the retirement of Craig Unit 1 by December 31, 2025. The Department also did not make any attempt to give "due consideration" to the needs of Colorado, nor did it make any attempt to consult with the CoPUC or Colorado Air Pollution Control Division.[327]

F. The Renewed Order is designed to support the federal administration's policy goal of propping up the coal industry, making it an arbitrary and capricious pretext.

Agency action is arbitrary and capricious when it rests on a "pretextual" reason that is "incongruent with what the record reveals about the agency's priorities and

[323] 42 U.S.C. § 7113.
[324] The Department, *Order No. 202-25-3B* (Sep. 8, 2025).
[325] § 25-7-102(2)(g)(I), Colo. Rev. Stat.
[326] § 25-7-105(1)(e)(VIII)(I), Colo. Rev. Stat.
[327] Exhibit B; Exhibit C.

decision-making process."[328] Agency decisions that feature "unjustifiable bias or partisanship are precisely the types of agency actions that 'would work a violation of the arbitrary-and-capricious standard.'"[329] Here, the record demonstrates that there is no evidence of an energy emergency within the meaning of Section 202(c) that would support issuance of the Renewed Order. Instead, the Renewed Order is a transparent attempt to favor the Trump administration's preferred energy source and revive the coal industry. Because the Renewed Order is pretextual and divorced from any actual emergency, the Renewed Order violates the law and must be withdrawn.

i. The federal administration intends to promote coal.

Over the course of 2025 and 2026, the Department and the President have made clear that they are using Section 202(c) orders to prevent coal-fired generating plants from retiring, simply because the current administration prefers coal and other fossil fuel generation. On his first day in office, the President declared a "National Energy Emergency" and identified coal as one of his preferred energy resources.[330] The President later directed the Department to "streamline" its use of emergency orders, explaining that his goal was to "revitaliz[e] America's big beautiful coal industry to support grid stability and American jobs."[331] In July, Secretary Chris

[328] *Dep't of Commerce*, 588 U.S. at 785.
[329] *Level the Playing Field*, 961 F.3d at 464 (quoting *Hagelin v. FEC*, 411 F.3d 237, 242 (D.C. Cir. 2005)).
[330] Exec. Order 14156, 90 Fed. Reg. 8433, 8434 (Jan. 20, 2025), Sec. 8(a).
[331] The White House, *Fact Sheet: President Donald J. Trump Strengthens the Reliability and Security of the United States Electric Grid* (Apr. 8, 2025); *see also* New York Times, Trump Signs Orders Aimed at Reviving a Struggling Coal Industry, April 8, 2025); Exec. Order 14261, Reinvigorating American's Beautiful Clean Coal Industry and Amending Executive Order 14241, 90 Fed. Reg. 15517 (April 14, 2025); Exec. Order 14260, Protecting American Energy from State Overreach, 90 Fed. Reg. 15513 (April 14, 2025); Regulatory Relief for Certain Stationary Sources To Promote American Energy, 90 Fed. Reg. 16777 (April 21, 2025).

Wright stated "'I think our biggest impact by far is going to be — there are like 40 coal plants that are supposed to close this year — and our biggest impact is going to be to stop the closure of most of those[.]'"[332]

Both the Department and President Trump have publicly acknowledged that their goal is to regulate long-term resource adequacy and mandate coal generation. Secretary Wright has stated that "[t]he goal [of the recent Section 202(c) orders] is to stop the political closure of coal plants."[333] The "Clean Beautiful Coal" Executive Order directed the Department to "identify regions where coal-powered infrastructure is available and suitable for supporting [artificial intelligence ("AI")] Data centers; assess the market, legal and technological potential for expanding coal-based infrastructure to power data centers to meet the electricity needs of AI…"[334] Most recently, the President received a trophy proclaiming him the "Undisputed Champion of Beautiful Clean Coal" after issuing yet another executive order, this time ordering the Department of War to purchase coal power.[335]

These statements and actions demonstrate a clear intention to use coal plants to meet long-term resource adequacy needs, which exceeds the Department's Section 202(c) emergency authority.

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[332] Young, C., *Engergy Secretary Chris Wright: Future of U.S. coal is 'long and bright'* (July 7, 2025).
[333] Exhibit III, (Brown, C., Plumer, B., *Trump Wants to Halt Almost All Coal Plant Shutdowns. It Could be Messy* (Jan. 16, 2026)), at 1.
[334] Exec. Order No. 14241, 90 Fed. Reg. 15517 (Apr. 14, 2025).
[335] Shah, S., *Coal Power is Rebounding in the U.S. Here's How it Happened* (Mar. 3, 2026); Exec. Order 14386, Strengthening United States National Defense With America's Beautiful Clean Coal Power Generation Fleet, 91 Fed. Reg. 7393 (Feb. 17, 2026).

ii. The Department's 2025 and 2026 Section 202(c) orders demonstrate a pattern of arbitrary and capricious behavior designed to carry out a policy goal.

In line with the policy goals described above, the Department has issued orders for nearly every coal plant scheduled to retire in 2025, all for the statutory maximum of 90 days. All of these orders have been summarily renewed in 2026, some now for the third time. None of these orders or their renewals meet the same criteria as previous orders issued pursuant to Section 202(c). Specifically, none were publicly requested by a utility;[336] none were based on an inability to comply with environmental laws; and none were responsive to or tailored to meet a specific, imminent, unexpected and temporary emergency. The Department, Secretary Wright has confirmed that "[t]he goal [of the recent 202(c) orders] is to stop the political closure of coal plants."[337] These orders have claimed emergencies in arbitrary and changing regions, largely based on a variety of NERC assessments that describe a host of different circumstances and reach varied conclusions. For example, in the Original Order for Craig Unit 1, the Department claimed an emergency in the WECC-Northwest assessment area, based on the 2024 LTRA, despite the fact that the Winter 2025-2026 NERC assessment was much more relevant for an order extending from Denver to March. Now, in the Renewed Order, the geographic area of the claimed emergency has changed to WECC-Rocky Mountain because of realignment in the assessment areas, and yet according to the Department, the claimed "emergency" still exists in

[336] It is common practice for the Department to post the request of the entity requesting a specific order within that order's docket. *See, e.g.* Department, *2024 DOE 202(c) Orders* (2024); Department, *2023 DOE 202(c) Orders* (2023).
[337] Exhibit III, at 1.

this new area, and Craig Unit 1 is still the best way to meet that emergency. The Department failed to acknowledge or explain this change. The Department is pointing to cherry picked information from each report to arbitrarily find an emergency to support a single solution (prevention of a planned coal plant retirement), even though it looked at two completely different geographic areas between the first and second report. This is evidence of arbitrary pre-judgment.

Additionally, the Department has issued Section 202(c) orders for closing coal plants in complete disregard of their condition or age. For example, the most recent Section 202(c) order to keep R.M. Schahfer Plant Units 17 and 18 running ignores the fact that Unit 18 was in a forced outage from February 16, 2025 to June 23, 2025, and then again starting on July 9, 2025. As of March 24, 2026, the unit was still in forced outage.[338] It is unclear how a plant that barely operated throughout 2025 and was not operational at the time the Department issued its original or renewed Section 202(c) orders could help in an alleged emergency. Similarly, when the Original Order was issued, Craig Unit 1 was in a forced outage and was not repaired until a third of the way into the period of the Original Order.

Every single Section 202(c) order to keep a retiring coal plant online in 2025 and 2026 has been challenged. The Department has summarily denied the numerous requests for rehearing challenging each of these orders, often with no substantive explanation. Before the Culley Order was renewed, the Region President of its operating utility asked the Department to not issue another Section 202(c) order

[338] IURC STATE OF INDIANA, *3/24 – Public Meeting* (YouTube, Mar. 24, 2026), at 3:16:22.

because Culley Unit 2, which is 60 years old, "will require substantial investment to support an inefficient and increasingly unreliable asset, rather than advancing affordable and reliable service for customers in southwestern Indiana."[339] The Department ignored this and issued a renewed Culley Order. The Department also did not substantively respond to Tri-State and PRPA's request for rehearing of the Original Order, ignoring their request that the Department work with them to find a more effective and affordable path forward to meet the Department's concerns.[340]

Together, the Department's orders demonstrate that, rather than addressing emergencies, the Department is working to prevent the retirement of coal plants across the United States as part of their larger efforts to bolster the coal industry.[341]

iii. Despite claims it is addressing energy emergencies, the Department is simultaneously interfering with efforts to increase generation through renewable resources.

At the same time the Department is claiming that an energy emergency justifies exercise of its Section 202(c) emergency authority, it is also working to stymie development of renewable generation sources, particularly wind and solar. It has also failed to acknowledge that Craig Unit 1's continued operation will also

[339] Letter from Michael Roeder, President, Indiana Region, to the Honorable Chris Wright, Secretary fo Energy (Feb. 17, 2026), at 1.
[340] Exhibit UU, at 5-6.
[341] *See, e.g.*, The Department, Energy Department Converse First National Coal Council Meeting Under Renewed Charter, Reaffirming Coal's Role in Unleashing American Energy (Jan. 15, 2026)https://www.energy.gov/articles/energy-department-convenes-first-national-coal-council-meeting-under-renewed-charter; The Department, *Energy Department Announces $175 Million to Modernize Coal Plants, Keeping Affordable Reliable Power Online for Americans* (Feb. 11, 2026); The Department, *Fact Sheet: The Department of Energy Is Ending The War On Beautiful, Clean Coal* (Jan. 15, 2026); *see also* Exec. Order 14261, Reinvigorating American's Beautiful Clean Coal Industry and Amending Executive Order 14241, 90 Fed. Reg. 15517 (April 14, 2025).

prevent the use of solar electricity generated by a newly added solar farm in Moffat County due to limited transmission capacity.[342]

The Department's own website explains that "wind energy offers many advantages which explains why it's one of the fastest-growing energy sources in the world[,]"[343] and that solar energy "can support household savings, energy independence, economic opportunities, grid reliability, resilience, security and affordability, and a safer planet."[344] Wind and solar energy are also extremely cost competitive with other energy sources. The most recent Levelized Cost of Energy+ Report ("LCOE Report") found that "[o]n an unsubsidized $/MWh basis, renewable energy remains the most cost-competitive form of generation."[345] Renewables are also important in a high demand scenario, as they are the "quickest-to-deploy generation resources."[346] Colorado has confirmed that wind and solar energy are low cost options to provide reliable electricity generation in the Northwest Colorado region, including Craig Unit 1.[347]

Despite these advantages, the federal government and the Department have been actively repressing wind, solar, and hydrogen fuel deployment. Alongside the Energy Emergency Executive Order, President Trump issued an executive

[342] *See* Exhibit UU.
[343] Department, *Advantages and Challenges of Wind Energy*.
[344] Department, *Solar Energy*.
[345] Lazard LCOE, *Levelized Cost of Energy+* (June 2025), at 4.
[346] *Id.*
[347] *See* Colorado Energy Office, *Exploring Advanced Energy Solutions for Rural Colorado* (Dec. 19, 2025) (study looked at both the levelized cost of energy and the levelized cost of capacity for multiple generation options and found that solar combined with battery storage has the lowest levelized cost of electricity, and wind combined with battery storage has the lowest cost levelized net cost of capacity).

memorandum ("Memo") directing federal agencies to pause the issuance of all wind energy authorizations.[348] That Memo has since been declared unlawful and vacated.[349] In addition, the One Big Beautiful Bill Act ended subsidies for wind and solar energy projects years earlier than planned.[350] The Department has also cut funding for grants that were supposed to go to projects such as hydrogen technology and upgrades to the electric grid.[351] And although the solar industry installed nearly 18 GW of new capacity in the first half of 2025, the federal administration's efforts to stymie wind and solar energy has resulted in significantly reduced solar deployment.[352]

More recently, the federal government has announced that it will pay an energy developer almost $1 billion in taxpayers funds to cancel federal leases for two offshore wind projects, in exchange for a commitment from the company to reinvest in oil and gas projects.[353] President Trump has gone as far as to admit that his "goal is to not let any windmill be built. . . . They're losers."[354] In line with these policy

[348] Temporary Withdrawal of All Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects, 90 Fed. Reg. 8363 (Jan. 29, 2025).
[349] Judgement Ordered 12/18/2025 in *State of New York v. Trump*, 25-cv-11221-PBS (D. Mass.).
[350] Sidley, *The "One Big Beautiful Bill" Act – Navigating the New Energy Landscape* (Jul. 15, 2025); *see also* 26 U.S.C.A. § 45Y (creating wind production tax credits, passed Aug. 2022); 26 U.S.C.A. § 48E (creating solar investment tax credits, passed Aug. 2022); One Big Beautiful Bill Act, Pub. L. 119-21, Title VII, § 70512-3, 139 Stat 72 (July 4, 2025) (amending 26 U.S.C.A § 45Y and 26 U.S.C.A. § 48E to end subsidies for wind and solar projects).
[351] *See* Walton, R., *DOE cancels $7.6B in clean energy awards in states that voted against Trump* (Oct. 2, 2025); Banse, T., *Trump administration yanks funding for Northwest green hydrogen project* (Oct. 2, 2025); Kaufman, A., *Trump's cuts to billion-dollar hydrogen hubs rattle industry* (Oct. 2025).
[352] Wood Mackenzie, *Solar and storage dominate new power additions in first six months of Trump administration as federal policies drive up energy costs* (Sept. 9, 2025); Economy+Environment, *Clean Economy Works: November 2025 Analysis* (Dec. 12, 2025).
[353] U.S. Department of the Interior, *Interior and TotalEnergies Agree to End Offshore Wind Projects, Lowering Costs for American Families* (Mar. 23, 2023).
[354] Exhibit JJJ (Harder, A., *Exclusive: Wind projects pile up as Pentagon reviews stall* (Mar. 30, 2026)), at 3.

goals, the Department of Interior has cancelled 30 onshore wind farm projects, thereby stalling around 7.5 GWs of capacity.[355] The Rural Energy for America program has also been put on hold, and forthcoming changes will discourage larger-scale solar projects.[356]

As the Department has observed, "the reliability of the power grid is intrinsically a system-wide property that cannot be ensured by an individual resource or technology in that system."[357] Focusing on one technology instead of a portfolio of resource adequacy measures increases risk.[358] The Department's current single-minded focus on coal and other fossil fuels reflects a policy preference as opposed to a desire to address any actual energy emergency, and constitutes an unlawful pretext.

G. The Department failed to comply with NEPA.

By requiring Craig Unit 1 to remain available beyond its planned retirement date, the Renewed Order has the potential to cause significant environmental impacts and requires evaluation under NEPA, particularly as it now seems clear the Department will continue issuing renewals regardless of the existence of an emergency.[359] Because the Department has misused its emergency authority in the Renewed Order,[360] it cannot rely on the exception to NEPA's implementing procedures that applies to emergency actions. Quite simply, there is no "emergency situation[]

[355] *Id.*, at 2.
[356] Heller, M., *Trump's opposition to renewables stalls rural energy grants* (Apr. 1, 2026).
[357] Department, *The Future of Resource Adequacy* (Apr. 2024) at 8.
[358] *Id.*
[359] 42 U.S.C. § 4336(b), *supra*.
[360] *See supra,* Sections V.A-F.

that demand[s] immediate action" here.[361] As demonstrated above, there is no current or imminent energy shortfall or near-term reliability emergency that justifies continued operation of Craig Unit 1.[362] Accordingly, to the extent the Department is relying on the exception for emergency actions to avoid full NEPA analysis, such reliance is contrary to law.

Moreover, the Department's NEPA implementing regulations recognize that where an action has the potential to cause significant impacts on an environmentally sensitive area, such as federally- and state-designated wilderness areas, national parks, scenic areas, and similar resources, the action is not appropriate for categorical exclusion and instead must be analyzed under NEPA.[363] Here, retirement of Craig Unit 1 by December 31, 2025 is a requirement of Colorado's federally approved SIP to address the federal Clean Air Act visibility program. This program is designed to protect federally-designated areas home to sensitive ecosystems or species potentially harmed by even small increases in pollution.[364] Specifically, the Colorado Regional Haze SIP, which incorporated Craig Unit 1's retirement date in Round 1, is designed to protect national parks and wilderness areas in Colorado including Black Canyon of the Gunnison National Park, Great Sand Dunes National Park, Rocky Mountain National Park, and Mount Zirkel Wilderness Area.[365] Craig Unit 1

[361] 10 C.F.R. § 1021.103.
[362] *See supra,* Section V.C.
[363] 10 C.F.R. Part 1021, Appx. B, § B(4)(iv).
[364] Exhibit B, ¶ 27.
[365] Exhibit MM (Division, *Colorado Visibility and Regional Haze SIP for the Twelve Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016)).

is located near the Mount Zirkel Wilderness Area.[366] As a result, the Department's own NEPA regulations dictate that the action was subject to NEPA review.

VI. Request For Stay

In addition to seeking rehearing, the State of Colorado moves the Department for a stay of the Renewed Order until the conclusion of judicial review.[367] The Department should also refrain from renewing the Renewed Order as currently drafted beyond its current expiration in March 2026. The Department has the authority to issue a stay under the Administrative Procedure Act and should do so where "justice so requires."[368] In deciding whether to grant a request for stay, agencies consider: (1) whether the party requesting the stay will suffer irreparable injury without a stay; (2) whether issuing a stay may substantially harm other parties; and (3) whether a stay is in the public interest.[369]

Injuries under this standard must be actual, certain, imminent, and beyond remediation.[370] Financial injury is irreparable where no "adequate compensatory or other corrective relief will be available at a later date, in the ordinary course of litigation."[371] Environmental injury, however, "can seldom be adequately remedied

[366] 5 Colo. Code Regs. § 1001-5:F.VI. (2014).
[367] 18 C.F.R. § 385.212.
[368] 5 U.S.C. § 705.
[369] *See Nken v. Holder*, 556 U.S. 418, 434, 436 (2009); *Ohio v. EPA*, 603 U.S. 279, 291 (2024); *see, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,020, at P 41 (2023); *ISO New Eng. Inc.*, 178 FERC ¶ 61,063, at P 13 (2022), *rev'd on other grounds sub nom. In re NTE Conn., LLC*, 26 F.4th 980, 987-88 (D.C. Cir. 2022).
[370] *Mexichem Specialty Resins, Inc. v. EPA*, 787 F.3d 544, 555 (D.C. Cir. 2015); *Wis. Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985); *ANR Pipeline Co.*, 91 FERC ¶ 61,252, at p. 61,887 (2000); *City of Tacoma*, 89 FERC ¶ 61,273, at p. 61,795 (1999) (recognizing that, absent a stay, options for "meaningful judicial review would be effectively foreclosed").
[371] *Wis. Gas Co.*, 758 F.2d at 674 (quoting *Va. Petroleum Jobbers Ass'n v. Fed. Power Comm'n*, 259 F.2d 921, 925 (D.C. Cir. 1958)); *see also In re NTE Conn., LLC*, 26 F.4th at 990-91. (Colorado refuses to

by money damages and is often permanent or at least of long duration, *i.e.*, irreparable. If such injury is sufficiently likely, therefore, the balance of harms will usually favor the issuance of an injunction to protect the environment."[372]

A. Colorado and its people will suffer irreparable injury absent a stay.

Here, a stay is necessary to prevent irreparable harm to the State of Colorado. Craig Unit 1 emits dangerous air pollutants that would not otherwise occur but for the Renewed Order. Craig Unit 1's continued availability and operation increases costs, which have already been passed on to ratepayers, along with increasing pollution directly through readying activities, and indirectly through the sourcing and transportation of fuel. Even if the unit dispatches rarely, these excess pollutants contribute to and exacerbate respiratory problems, cardiovascular issues, and other health conditions.[373] By continuing to delay the retirement of a 45-year-old coal-fired unit, the Department is causing Colorado's electric customers to be served by a more costly and less reliable and resilient electric grid. Instead of continuing to invest in and develop more reliable resources as planned, the Craig Unit 1 Owners will have to dedicate resources to repair and maintain a coal plant that is less reliable and more costly than other generation resources.

A stay would not result in harm to any other interested parties. The issuance of a stay would not harm end-use electricity consumers because there is no emergency

concede that its residents, as ratepayers, should bear this cost of the Department's illegal actions here. Nonetheless, we assume that neither the Department nor the Craig Station owners want to bear those costs either, and will seek to impose them on Coloradans.).

[372] *Amoco Prod. Co. v. Vill. of Gambell*, 480 U.S. 531, 545 (1987).

[373] Exhibit B, ¶ 22.

addressed by the operation of Craig Unit 1. The lack of an actual emergency means that a stay would not disrupt the provision of electricity. Furthermore, because Tri-State had already planned for the closure of Craig Unit 1, a stay would have the effect only of relieving Tri-State of the administrative, compliance, and planning burdens imposed by the Renewed Order. On the balancing of equities, there is therefore no meaningful countervailing harm that would follow from a stay.

B. A stay is in the public interest.

There is no public interest served by the Renewed Order, and a stay will only benefit the public. First, the Renewed Order exceeds the Department's authority; it has provided no reasonable grounds to substantiate any near-term or imminent shortfall in electricity supply that would necessitate Craig Unit 1's continued operation.[374] Second, a stay would protect the broader public from the costs and additional pollution produced by unnecessary operation of Craig Unit 1.

VII. Conclusion

For the reasons set forth above, the State of Colorado respectfully requests that the Department grant intervention; grant a rehearing and rescind the Renewed Order; and stay the Renewed Order.

[374] *See League of Women Voters v. Newby*, 838 F.3d 1, 12 (D.C. Cir. 2016) (noting that "there is a substantial public interest 'in having governmental agencies abide by the federal laws that govern their existence and operations'") (quoting *Washington v. Reno*, 35 F.3d 1093, 1103 (6th Cir. 1994)).

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Certificate of Service

This is to certify that I have duly served the foregoing, **The State Of Colorado's Request For Rehearing, Motion to Intervene, and Stay Request**, upon all parties below electronically via e-mail this 28th day of April, 2026:

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State of Colorado's Exhibit List

Exhibit No.	Document Description
A	Department, Order No. 202-25-14 (Dec. 30, 2025)
B	Declaration of Josh Korth Declaration (Apr. 27, 2026)
C	Declaration of Erin O'Neil (Apr. 28, 2026)
D	Declaration of Joseph Pereira (Apr. 24, 2026)
E	CoPUC, Decision No. C25-0612, issued on August 26, 2025, in Proceeding No. 23A-0585E.
F	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-2, (Tri-State, *2020 IRP/ERP,* Public (Dec. 1, 2020))
G	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-1 (Tri-State, *Responsible Energy Plan* (Jan. 2020)
H	Salt River Project, 2023 Integrated Systems Plan
~~I~~	Department, Order No. 202-25-7 (Aug. 20, 2025)
J	CoPUC, 120 Day ERP Implementation Report, Public, filed on April 11, 2025, in Proceeding No. 23A-0585E
K	NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024)
L	NERC, *2025-2026 Winter Reliability Assessment* (Nov. 2025)
M	Department, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (July 2025)
N	Motion to Intervene and Protective Request for Rehearing by the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York, filed on August 6, 2025 with the Department
O	Department, Order No. 202-25-3 (May 23, 2025)
P	Department, Order No. 202-25-4 (May 30, 2025)
Q	Department, Order No. 202-25-11 (Dec. 16, 2025)
R	Department, Order No. 202-25-13 (Dec. 23, 2025)
S	Department, Order No. 202-25-12 (Dec. 23, 2025)
T	Congressional Research Service, *Federal Power Act: The Department of Energy's Emergency Authority* (June 12, 2025)
U	Department, Order No. 202-25-9 (Nov. 18, 2025)
V	Department, Order No. 202-25-8 (Aug. 28, 2025)
W	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E
X	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 (Tri-State, 2023 ERP Phase I, Rev. 2 (Apr. 22, 2024)

Y	CoPUC, Verified Petition of Trial Staff of the Commission, CEO, UCA, and Public Service for a Variance from Decision No. C18-0761 and Any Other Requirements, Request for Shortened Notice and Intervention Period, and Request for Approval of Associated Procedures, filed on November 10, 2025, in Proceeding No. 25V-0480E
Z	CoPUC, Tri-State, *2025 Annual Progress Report*, filed on December 1, 2025, in Proceeding No. 23A-0585E
AA	CoPUC, Decision No. R24-0602, issued on August 22, 2024, in Proceeding No. 23A-0585E
BB	CoPUC, Decision No. C25-0892, issued on December 10, 2020, in Proceeding No. 25V-0480E
CC	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1-Attachment F (*Electric Energy and Demand Forecast*, Public)
DD	CoPUC, Hrg. Ex. 103, Direct Testimony and Attachments of Brian L. Thompson, Rev. 1, filed on May 24, 2024, in Proceeding No. 23A-0585E
EE	PRPA, 2024 Integrated Resource Plan (Apr. 2023)
FF	PRPA, Craig Units 1&2 (Yampa Project) (2026)
GG	PacifiCorp, Utah Integrated Resource Plan Volume I (Mar. 31, 2025)
HH	SPP, *SPP Reliability Plan* (June 2, 2025)
II	NERC, *Emergency Operations*
JJ	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Proceeding 20A-0528E
KK	Division, *Operating Permit No. 96OPMF155* (July 1, 2021)
LL	Division, *Technical Review Document for Operating Permit 96OPMF155* (Jan. 2005)
MM	Tri-State, General APEN- Form APCD-200 (Apr. 21, 2025)
NN	Division, *Colorado Visibility and Regional Haze SIP for the Twelve Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016)
OO	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 – Attachment G-1 (Astrape Consulting, *Reserve Margin and Effective Load Carrying Capability (ELCC) Study*, Public (Aug. 2, 2023)
PP	Department, Order No. 202-25-10 (Nov. 25, 2025)
QQ	Tri-State, *U.S. DOE Orders TriState to Keep Craig Generating Station Unit Operating for Next 90 Days* (Dec. 31, 2025)
RR	Powell, R., 1 coal plant open amid order (Jan. 6, 2026)
SS	Behr, P., *PJM to ratchet down projected AI power demand for eastern US* (Jan. 6 , 2026)
TT	Department, Order No. 202-26-21 (Mar. 30, 2026)

UU	Tri-State, *Request for Clarification and for Rehearing of Tri-State Generation and Transmission Association and Platte River Power Authority* (Jan. 29, 2026)
VV	CoPUC, Tri-State, Notice of 2026 Resource Adequacy Annual Report, filed on March 17, 2026, in Proceeding No. 26M-0028E
WW	NERC, *Long-Term Reliability Assessment* (Jan. 2026)
XX	Department, Order No. 202-26-16 (Feb. 17, 2026)
YY	Department, Order No. 202-26-17 (Feb. 23, 2026)
ZZ	Department, Order No. 202-26-18 (Mar. 16, 2026)
AAA	Department, Order No. 202-26-19 (Mar. 23, 2026)
BBB	Department, Order No. 202-26-20 (Mar. 23, 2026)
CCC	State of Colorado, The State of Colorado's Request for Rehearing, Motion to Intervene, and Stay Request (Jan. 28, 2026)
DDD	Letter from Jerome H. Sturhahn, Senior Vice President of Tri-State, to Shannon McMillian, Compliance and Enforcement Program Manager, CDPHE (Jan. 26, 2026)
EEE	CoPUC, Tri-State, Notice Regarding Phase II Developments, filed on March 17, 2026, in Proceeding No. 23A-0585E
FFF	SPP, *Current Gird Conditions* (Apr. 7, 2026)
GGG	SPP, *Current Gird Conditions* (Apr. 20, 2026)
HHH	Cook, A., *NERC to OMS: Long-term Assessment not a Predictor of Risk* (Feb. 10, 2026)
III	Brown, C., Plumer, B., *Trump Wants to Halt Almost All Coal Plant Shutdowns. It Could be Messy* (Jan. 16, 2026)
JJJ	Harder, A., *Exclusive: Wind projects pile up as Pentagon reviews stall* (Mar. 30, 2026)

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit MMM: Tri-State, Request for Clarification and for Rehearing of Tri-State Generation and Transmission Association and Platte River Power Authority (Apr. 29, 2026)

UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY

In re Craig Order No. 202-26-21	)	Order No. 202-26-21
	)	

REQUEST FOR REHEARING OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION AND PLATTE RIVER POWER AUTHORITY

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Pursuant to Section 313(a) of the Federal Power Act (FPA),[1] and Rule 713 of the Rules and Regulations of the Federal Energy Regulatory Commission (FERC or Commission),[2] and the applicable rules of practice and procedure,[3] Tri-State Generation and Transmission Association, Inc. (Tri-State) and Platte River Power Authority (Platte River) (together, Petitioners) file this Request for Rehearing of Order No. 202-26-21 dated March 30, 2026 (the Order) requiring Petitioners and their co-owners to keep coal-fired Unit 1 of the Craig Generating Station in Craig, Colorado (Craig Unit 1) open and available to operate notwithstanding its long-planned retirement. Craig Unit 1 was originally scheduled to shut down by December 31, 2025.[4]

SUMMARY

Section 202(c) provides that "during" an emergency, the U.S. Department of Energy (DOE) is authorized to require extraordinary steps be taken to serve the public interest. 16 U.S.C. § 824a(c)(1). The Order finds that such an emergency exists—but indicates that the claimed energy shortages DOE has identified are not likely to occur, if ever, until ***2034***—more than seven years—or ***thirty-one*** 90-day

[1] 16 U.S.C. § 825l.

[2] 18 C.F.R. § 385.713 (2026).

[3] U.S. Dep't of Energy, DOE Rehearing Procedures, https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (last visited Jan. 15, 2026); *see also* 18 C.F.R. §§ 385.214 (2026), 385.713.

[4] Petitioners are co-owners of Craig Unit 1, and named recipients of the Order. Under the Commission's rules and regulations they are parties to this proceeding. However, if necessary to give them party status, out of an abundance of caution, Petitioners ask that this filing also be treated as a motion to intervene under Rule 214 of the Commission's Rules and Regulations. Petitioners' position on the Order and the nature of their interest are set forth in detail in this filing.

Section 202(c) renewal cycles in the future. That emergency, should it ever come to pass, cannot be solved by requiring that Craig Unit 1, a more than 45-year-old coal plant, continue operating today. It cannot be solved by allowing dispatch of Craig Unit 1 during the period of the current Order. While Petitioners raised many of these and other concerns in their request for rehearing and clarification responding to DOE's initial Section 202(c) order targeting Craig Unit 1,[5] this second Order provides little response.

Petitioners again request rehearing to bring to DOE's attention the myriad constitutional, procedural, and evidentiary defects of the Order. Regardless of whether the Order survives such scrutiny, it effects an uncompensated physical and regulatory taking of Petitioners' property interests in Craig Unit 1 and associated fuel and transmission resources. This taking does not come with just compensation, because (1) the processes by which Petitioners could potentially obtain recovery are insufficient and unclear; (2) and these processes fail to provide *compensation* from the taking party—the federal government—rather than facilitating potential compensation from private third parties (including Petitioners).

The Order is also defective on the merits. It fails to articulate a valid emergency, and its chosen remedy—keeping Craig Unit 1 open and available for dispatch—does not respond to the emergency it purports to identify. Because the

[5] *In re Craig Order No. 202-25-14*, Request for Clarification and for Rehearing of Tri-State Generation and Transmission Association and Platte River Power Authority (Jan. 29, 2026), https://www.energy.gov/documents/request-clarification-and-rehearing-tri-state-generation-and-transmission-association-and (the First Rehearing Request).

contemplated "emergency" does not occur until 2034, the Order fails to provide constitutionally adequate due process before deprivation of Petitioners' property interests. Similarly, the Order is procedurally defective; it fails to incorporate statutorily mandated consultation between DOE and other agencies and neglects to consider any alternatives to its proposed plan. Finally, the Order does not align with the statutory objectives of the Federal Power Act (FPA), and DOE never explains how it could.

Petitioners seek to work with all levels of government to provide consumers with reliable and affordable electricity. But Petitioners cannot fulfill this mission when agencies impede years of concerted planning and mandate disruptive and costly changes that do not promote reliability or affordability. This is not what Section 202(c) was intended for. Petitioners urge DOE to reconsider its approach.

STATEMENT OF ISSUES

Pursuant to FPA Section 313(a), Petitioners request clarification and, in the alternative, rehearing based on the following issues:

1. By mandating Craig Unit 1's availability to operate and the terms under which it shall operate, and requiring related changes to Petitioners' physical property, the Order constitutes both a physical and regulatory taking. Because the Order does not provide "just compensation" from the government, this is an uncompensated taking in violation of the Fifth Amendment to the United States Constitution. *United States v. Pewee Coal Co.*, 341 U.S. 114, 116 (1951); *Horne v. Dep't of Agric.*, 576 U.S. 351 (2015); *Ruckelshaus v. Monsanto Co.*, 467 U.S. 986, 1011 (1984).

2. Because DOE failed to establish the existence of an emergency, and, because of the temporal and geographic disconnect between the energy reliability concerns described by the Order and the means DOE directs for addressing those concerns as compared to alternatives, DOE failed to establish that the purported emergency here is addressed by the continued operation and dispatch of Craig Unit 1 or that the Order "best meet[s] the

emergency and serve[s] the public interest." 16 U.S.C. § 824a(c); 10 C.F.R. § 205.373 (2026). It is, therefore, contrary to law and arbitrary and capricious.

3. Because DOE predicated the Order on long-term concerns, and not an existing emergency, and reissued the Order notwithstanding the due-process objections Petitioners raised in their prior request for rehearing, Petitioners were denied any meaningful opportunity to be heard, notwithstanding time and notice permitting such process. This violates the Due Process Clause of the Fifth Amendment and is contrary to the procedural protections contemplated by the Administrative Procedure Act and the FPA. *Pa. Gas & Water Co. v. FPC*, 427 F.2d 568, 576 (D.C. Cir. 1970); *S. Allegheny Pittsburgh Restaurant Enterprises, LLC v. City of Pittsburgh*, 806 F. App'x 134, 139–41 (3d Cir. 2020).

4. The Order fails to incorporate any statutorily required consultation between DOE and the agency "with expertise in the environmental interest protected by" the laws or regulations waived by a renewed order. 16 U.S.C. § 824a(c)(4)(B). It is, therefore, contrary to law and arbitrary and capricious.

5. The Order does not align with the statutory objectives of the FPA, because it requires the operation and availability for dispatch of an uneconomic resource, and disrupts ordinary and orderly planning, development, and investment in generation resources. It is, therefore, contrary to law and arbitrary and capricious.

BACKGROUND

A. The Petitioners

Tri-State is a wholesale generation and transmission cooperative operating on a not-for-profit basis with its principal place of business in Westminster, Colorado. Organized and existing pursuant to the Colorado Cooperative Act,[6] Tri-State is a public utility subject to FERC jurisdiction under Part II of the FPA.[7] Tri-State is wholly owned by its electric distribution cooperative and public power district

[6] COLO. REV. STAT. § 7-55-101 *et seq.* (2019) (Cooperatives- General); Articles of Incorporation (2020).

[7] Tri-State Generation and Transmission Ass'n, 170 FERC ¶ 61,221, at P 37 (2020).

members (Utility Members) and three non-Utility Members (Non-Utility Members)[8] and was formed by its Utility Members for the purpose of providing the Utility Members with transmission services and wholesale power for resale to their retail customers.

Tri-State has 11 Utility Members with retail customers located in New Mexico and three Utility Members with retail customers in Nebraska,[9] all of which are outside the 2025 Western Electricity Coordinating Council (WECC) Rocky Mountain region that DOE identified as the region experiencing an emergency in the Order. The retail service territories of Tri-State's Utility Members cover approximately 182,000 square miles and their customers include rural residences, farms and ranches, and large and small businesses and industries, serving approximately 522,000 retail electric meters. Tri-State's Utility Members are the sole state-certificated providers of electric service to retail (residential and business) customers within their designated service territories.

Tri-State owns, directly or indirectly, or controls the output of, various power generation facilities, and purchases wholesale power within both the Western and Eastern Interconnections. Among other generation facilities, Tri-State is a partial owner of Craig Unit 1, with a 24% ownership share. Tri-State's generating facilities

[8] Tri-State's Non-Utility Members are: (i) MIECO, Inc., a wholesale supplier of natural gas in the United States; (ii) Olson's Greenhouses of Colorado, LLC, a grower/distributor of plants throughout the western United States that has a contract to purchase thermal energy from Tri-State; and (iii) Ellgen Ranch Company, which leases property from a Tri-State subsidiary.

[9] Tri-State has six Utility Members that maintain headquarters in Nebraska, three of which operate outside the emergency assessment area.

are included in the Western Power Pool reserve sharing program. This program facilitates sharing of generation reserves to be activated during a system emergency, such as loss of a generating unit or transmission line. Tri-State began participating in the Southwest Power Pool's (SPP) expanded regional transmission organization (RTO) in the Western Interconnection in April 2026.[10]

Platte River is a not-for-profit, municipally-owned power utility and joint action agency that generates reliable, financially sustainable, and environmentally responsible electricity for its owner communities of Estes Park, Fort Collins, Longmont, and Loveland, Colorado. Platte River is a political subdivision of the State of Colorado and a government-owned utility under FPA Section 201(f), 16 U.S.C. § 824(f). Headquartered in Fort Collins, Colorado, Platte River furnishes cost-of-service wholesale electrical power and energy to its four owner communities.

Platte River is a partial owner of Craig Units 1 and 2, with an 18% ownership share in the Craig units. Platte River's share of the total net capacity from both Craig units is 151 MW. Platte River also owns and operates an integrated transmission system of high-voltage aerial and underground power lines that deliver electricity to the electric utilities of Platte River's owner communities in Northern Colorado. Like Tri-State, Platte River began participating in SPP's expanded RTO in April 2026.

[10] As used herein, SPP refers to the SPP RTO's western expansion. It does not include SPP Markets+.

B. The Craig Generating Station

Craig Generating Station is a three-unit, coal-fired power plant located in Craig, Colorado. Craig Units 1 and 2 were built by and are jointly owned by several utilities through what is known as the Yampa Project. Tri-State operates those two units on behalf of all the co-owners, including Platte River, PacifiCorp, Public Service Company of Colorado, and Salt River Project. Tri-State separately owns and operates Craig Unit 3. In April 2026, the owners of Craig Units 2 and 3 became market participants in SPP—the culmination of a multi-year planning process—and began to bid those units into SPP's market. Craig Unit 1 is currently participating as a resource in SPP solely because of the Order.

As a result of changed market conditions and regulatory requirements, the retirement of the Craig units has been planned, reviewed, and integrated into state-approved resource portfolios, and the owners have planned for their closure for nearly a decade—beginning with Craig Unit 1 by December 31, 2025, followed by Craig Unit 3 by January 1, 2028, and Craig Unit 2 by September 30, 2028. Colorado Air Quality Control Commission Regulation No. 23 on Regional Haze Limits now specifies a retirement date for each Craig unit.[11] Unit 1's retirement date was adopted in 2016, in a revision of what was then Colorado Air Quality Control Commission Regulation No. 3, which was approved by the Environmental Protection Agency

[11] COLO. CODE REGS. 1001-27.

(EPA) in 2018.[12] Retirement dates for Craig units were later codified into Regulation No. 23.

The Craig units have been fueled primarily by coal from the nearby Colowyo and Trapper mines. The Colowyo Mine has ceased active mining and transitioned to full reclamation, with two pits in final reclamation and the third transitioned to reclamation on October 15, 2025. Similarly, the Trapper Mine is scheduled to cease active mining and convert to site remediation in calendar year 2026. Before the closure of the Colowyo Mine, Tri-State stockpiled sufficient coal to meet Tri-State's projected demand for Craig Units 2 and 3 through their respective planned retirement dates. Before the Trapper Mine closes, Platte River will have stockpiled sufficient coal to meet its projected demand for Craig Unit 2 through its planned retirement date.

As part of its multi-year resource plan, which incorporated the long-planned retirement of Craig Unit 1, Tri-State has placed into service the 145 MW Axial Basin generating facility. This facility, approximately 26 miles from the Craig facility, relies on much of the same transmission infrastructure. Absent the retirement of Craig Unit 1, this interconnection faces transmission constraints such that, when Craig Unit 1 remains interconnected and available to operate, Tri-State may be required to

[12] *See* Approval and Promulgation of Implementation Plans; Colorado; Regional Haze 5-Year Progress Report State Implementation Plan, 84 Fed. Reg. 47884 (Sept. 11, 2019); Co. Air Pollution Control Div., Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado (Dec. 15, 2016), https://oitco.hylandcloud.com/POP/DocPop/DocPop.aspx?docid=3303135.

curtail output from Axial Basin (particularly when all facilities are generating at or near full output) due to limited transmission capacity.

C. Craig Unit 1

Craig Unit 1 can produce up to 427 MW of electricity and has been running since 1980. Over the last ten years, the operations and maintenance cost (without consideration of coal cost or depreciation expense) to run Craig Unit 1 has totaled in the millions of dollars annually. By the standards of an older coal plant, Craig Unit 1 has generally provided reliable performance when called upon. However, in the last three years (due primarily to economic factors and some forced outages), Craig Unit 1 has run well below half of its capacity for Petitioners, without compromising Petitioners' ability to meet their generation demands reliably.

Operation and maintenance of Craig Unit 1 have been undertaken prudently to reflect the scheduled 2025 retirement. Since 2019, the Craig Unit 1 owners scheduled and performed only that maintenance appropriate for a unit that planned to cease operation at the close of 2025. On December 19, 2025, the unit suffered a valve failure that rendered Craig Unit 1 inoperable, although the unit is now available to operate following repairs.[13]

D. DOE Order No. 202-25-14

On December 30, 2025, DOE issued Order No. 202-25-14, declaring that "an emergency exists within the [WECC-NW] assessment area due to a shortage of

[13] Tri-State Generation & Transmission Ass'n, Inc., *U.S. DOE Orders Tri-State to Keep Craig Generating Station Unit Operating Next 90 Days*, TRI-STATE (Dec. 31, 2025), https://tristate.coop/us-doe-orders-tri-state-keep-craig-generating-station-unit-operating-next-90-days.

electric energy, a shortage of facilities for the generation of electric energy, and other causes." DOE Order No. 202-25-14 at 1 (Dec. 30, 2025). Petitioners sought rehearing and clarification of Order No. 202-25-14, raising multiple legal issues, including DOE's denial of Petitioners' constitutionally protected due process rights, the lack of an appropriate mechanism for just compensation, and DOE's failure to consider alternatives for what the order itself recognized was not an immediate, time-sensitive emergency. DOE denied the First Rehearing Request by operation of law pursuant to 16 U.S.C. § 825l(a) by failing to substantively respond to the request within 30 days, and issued a notice to this effect on March 2, 2026.

This initial order expired on March 30, 2026.

E. DOE Order No. 202-26-21

On March 30, 2026, DOE issued Order No. 202-26-21, continuing Order 202-25-14. The Order declared that "an emergency exists within the Western Electricity Coordinating Council (WECC) Rocky Mountain assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes." DOE Order No. 202-26-21 at 1 (Mar. 30, 2026). The Order further declared that "[t]he availability of electricity from Craig Unit 1 will continue to be critical to maintain reliability in the WECC Rocky Mountain assessment area." *Id.* at 3. Its emergency was predicated on (1) "increasing demand" and (2) "shortage from accelerated retirement of generation facilities [that] will continue in the near term and are also likely to continue in subsequent years." *Id.* at 6. DOE stated, "[t]his could lead to the loss of power to homes, and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety." *Id.*

DOE predicated its energy reliability concerns on the 2025 Long-Term Reliability Assessment (2025 LTRA) from the North American Electric Reliability Corporation (NERC) for the WECC-Rocky Mountain assessment area, which does not anticipate any shortfalls in supply before Summer 2034. *Id.* at 3. DOE also pointed to the 2025 WECC Western Assessment of Resource Adequacy. The concerns included (1) projected regional load growth; (2) planned retirement of generation facilities fueled by coal and natural gas; and (3) the "prolific growth of data centers" constituting a "new and unexpected source of load growth." *Id.* at 3–5.[14]

The Order requires Petitioners and the other co-owners of Craig Unit 1 to:

1. From March 31, 2026, take all measures necessary to ensure that Craig Unit 1 is available to operate at the direction of either Western Area Power Administration (WAPA)—Rocky Mountain Region, Western Area Colorado Missouri (WACM), in its role as Balancing Authority, or SPP West in its role as the Reliability Coordinator, as applicable.
2. From April 1, 2026, take all measures necessary to ensure that Craig Unit 1 is available to operate, with SPP directed to take every step to employ economic dispatch of Craig Unit 1 to minimize costs to ratepayers, with Tri-State and the co-owners directed to comply with all orders from SPP related to the availability and dispatch of Craig Unit 1.
3. Limit operation of Craig Unit 1 to the times and within the parameters established *supra* in order to minimize adverse environmental impacts, and to provide a daily notification to the Department reporting whether Craig Unit 1 has operated in compliance with the Order.
4. Comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the

[14] The Order placed these concerns in the broader context of Executive Orders 14156 and 14262. Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https:// www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency; Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

maximum extent feasible while operating consistent with the emergency conditions.

5. By April 14, 2026, provide DOE with information concerning the measures each has taken and is planning to take to ensure the operational availability of Craig Unit 1 consistent with the Order, as well as additional information regarding the environmental and operational impacts of the Order and its compliance with the conditions of the Order, in each case as requested by DOE.
6. File tariff revisions or waivers with FERC to effectuate the Order, as needed.

The Order is effective from March 31 through June 28, 2026. Tri-State has submitted and continues to submit daily notifications to DOE as the Order requires.

ARGUMENT

Petitioners seek rehearing on two fronts. *First*, the Order effectuates a taking of Petitioners' property under the Fifth Amendment to the United States Constitution without an adequate process to obtain constitutionally required compensation. *Second*, the Order does not meet either the Constitution's or Section 202(c)'s requirements for a reasoned, procedurally adequate finding of a valid emergency that compels operation of Craig Unit 1.

I. THE ORDER CONSTITUTES AN UNCOMPENSATED TAKING OF PETITIONERS' PROPERTY INTERESTS

Petitioners chose to close Craig Unit 1 to meet reliability targets and achieve regulatory goals, and have taken numerous steps over the years to prepare for its closure. The Order nevertheless requires Tri-State to operate the facility beyond that planned retirement date, effecting an uncompensated taking of Petitioners' property in violation of the Fifth Amendment of the United States Constitution. By compelling continued operational availability of Craig Unit 1, DOE took effective control over the

facility itself and mandated changes to Petitioners' infrastructure and business operations, constituting both a *per se* physical and regulatory taking.

The Order's taking comes with no constitutionally adequate avenue for just compensation. FERC cost recovery shifts compensation onto ratepayers; it does not assure compensation *from the government*. And, due in part to the broad scope of the declared energy emergency, FERC cost recovery related to the Order will be procedurally and substantively novel and could leave material costs unrecovered from the Order's putative beneficiaries.

A. The Order Constitutes a Physical Taking

The Fifth Amendment provides, "private property [shall not] be taken for public use, without just compensation." U.S. Const. amend. V. "When the government physically acquires private property for a public use, the Takings Clause imposes a clear and categorical obligation to provide the owner with just compensation." *Cedar Point Nursery v. Hassid*, 594 U.S. 139, 147 (2021) (citation omitted).

Physical takings can take various forms, including intermittent or limited-value intrusions. *Id.* at 149–55; *see also Loretto v. Teleprompter Manhattan CATV Corp.*, 458 U.S. 419 (1982). Moreover, "[i]f government action would qualify as a taking when permanently continued, temporary actions of the same character may also qualify as a taking." *Ark. Game & Fish Comm'n v. United States*, 568 U.S. 23, 26 (2012). This is true even when the government has not seized title to property but rather directed it to operate in a particular way. Temporary seizures of property to operate are takings "in as complete a sense as if the Government held full title and

ownership." *See Pewee Coal Co.*, 341 U.S. at 116 (quoting *United States v. United Mine Workers of Am.*, 330 U.S. 258, 285–86 (1947)).

The Order operates as a physical taking in two interrelated ways. *First*, by directing Petitioners to maintain and operate Craig Unit 1, on a prolonged basis, and in clear departure from Petitioners' own planned retirement of the facility, the Order falls within a near-century-old tradition of classifying mandatory operations—even under wartime and emergency authorities—as takings requiring compensation. *Second*, the Order constitutes a physical taking by compelling Petitioners to make material physical changes to the plant, including repairing out-of-service equipment like feedwater heater tubes, ash blowers, and side stream filter pumps, for example, requiring additional staff onsite, and physically diverting coal allocated for Craig Units 2 and/or 3 to fuel Craig Unit 1. Reduction of these stockpiled reserves requires Petitioners to obtain replacement coal that will be compatible for use in Units 2 and 3, from uncertain sources and at uncertain future prices, creating an additional uncompensated cost. And because of transmission constraints, Craig Unit 1's operations could limit the circumstances where SPP can dispatch the nearby Axial Basin generating facility.

1. The Order's Direction of Prolonged Operations at Craig Unit 1 Contrary to Petitioners' Plan to Retire the Facility Constitutes a Physical Taking

Section 202(c) was enacted to address energy shortages that occurred during the First World War,[15] making it particularly suitable for analysis under post-war interpretations of the Takings Clause. These cases show that, even in the context of an emergency, where the government takes control of part or all of a business's facilities to use and operate for the government's purposes, a compensable taking occurs, *see*, *e.g.*, *United States v. Gen. Motors Corp.*, 323 U.S. 373 (1945) (government seizure of part of leased warehouse space for military purposes was a compensable taking). Similarly, where the government requires a private business to operate in the public interest, this too constitutes a *per se* physical taking. *Pewee Coal Co.*, 341 U.S. at 116 (taking occurred when government responded to work stoppages and strikes at coal mines by directly operating them or arranging for their continued operation). Finally, these cases illustrate that a taking is particularly likely to occur where the imposition of government control extends over a lengthy period of time. *See Gen. Motors Corp.*, 323 U.S. at 375 (warehouse seized for more than a year); *Pewee Coal Co.*, 341 U.S. at 115 (government-directed operation of coal mine continued for more than 160 days).[16]

[15] Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789, 789–846, 800–02 (2024) ("Rolsma (2024)").

[16] Indeed, the federal government recently recognized that where the government appropriates the right to control operation of a facility and deprives owners of their freedom to dispose of their property, a taking has occurred. *See* EPA-R08-OAR-2024-0607-0067, Regional Haze Round 2 at 19–21 (Jan 9, 2026), https://www.regulations.gov/document/EPA-R08-OAR-2024-0607-0067 (describing how the "unconsented closure" of a coal-fired power

In that light, the Order constitutes a taking of Petitioners' property. The Order requires Petitioners to, in relevant part: (1) take all measures necessary to ensure that Craig Unit 1 is available to operate; (2) limit operation of Craig Unit 1 to certain times and parameters; and (3) make Craig Unit 1 available for dispatch at the direction of SPP, a non-governmental actor. Compliance with these requirements has compelled Petitioners to take significant steps, steps they would not otherwise take, for a prolonged period of time. DOE's renewed Order extends the period of compelled availability to roughly six months, and nothing in the Order suggests this control will be temporary rather than renewed through successive emergency declarations. This closely resembles the mandate to operate that the *Pewee Coal* Court held was a taking.[17] By requiring Petitioners to involuntarily keep Craig Unit 1 available for operations according to SPP's instructions—for not hours or days but months—DOE enacts a taking.

2. The Order Mandates Physical Changes to Petitioners' Property That Constitute a Physical Taking

The physical changes to Petitioners' property mandated by the Order also constitute a *per se* physical taking of Petitioners' property rights in Craig Unit 1 and other related property, such as fuel. *First*, operations require fuel, which compels

station constituted a per se taking of the facility owner's property) (citing *Cedar Point Nursery v. Hassid*, 594 U.S. 139 (2021) and *Horne v. Dep't of Agric.*, 576 U.S. 351 (2015)).

[17] The *Pewee Coal* Court did not enjoin the government's actions—the wartime emergency justified the government's effort to keep coal mines operational in 1943, the heat of the war. The fact of a justified emergency, however, did nothing to abate the Takings Clause requirement that the government compensate the plaintiff. *See Pewee Coal Co.*, 341 U.S. at 118 (holding that government is "entitled to the benefits and subject to the liabilities" of operating a facility it takes over).

Petitioners to make use of the Craig facility's limited fuel reserves intended exclusively for Craig Units 2 and/or 3 as operations at Unit 1 continue; these reserves were acquired and measured for the anticipated operation of two specific coal units and based on the assumption that Craig Unit 1 would retire at the end of 2025. Because the Order forces Petitioners to surrender coal inventory for the government's chosen public purpose—coal that Petitioners acquired, allocated, and reserved for other units—it effects a *per se* physical taking of that property. *Second*, transmission capacity limitations for Petitioners' facilities at and near Craig Unit 1—the other Craig units and Axial Basin—mean that requiring Craig Unit 1 to remain interconnected and possibly operating constrain the ability of these resources to fully access the grid. And *third*, mandating that Petitioners make Craig Unit 1 ready for operations has compelled Petitioners to make material physical changes to Craig Unit 1, including repairing out-of-service equipment that would otherwise remain unused.

a. The Craig Facility's Fuel Reserve

All three Craig Units were designed to run on coal obtained from the now-shuttered Colowyo Mine and the soon-to-be-shuttered Trapper Mine.[18] Before closing the Colowyo Mine, Tri-State stockpiled reserves sufficient to operate its share of the Craig Units until their respective retirements. The only readily available source of

[18] Tri-State believes that co-owners supply their share of Craig Units 1 and 2 through Trapper or other mines.

fuel for Craig Unit 1 to maintain readiness, and to make use of in the event of a dispatch, are the reserves acquired and allocated for Craig Units 2 and 3.[19]

This too constitutes a taking. *See Horne*, 576 U.S. at 357–65 (USDA requirement that a percentage of a grower's crop be set aside for public use constituted a *per se* physical taking). Just as the government in *Horne* effected a *per se* taking by requiring raisin growers to surrender a specific, identifiable portion of their crop for public use, by mandating that Petitioners consume coal inventory purchased and reserved for Craig Units 2 and/or 3, DOE appropriates that property for a public objective. Under *Horne*'s reasoning, forced depletion of a utility's fuel reserves—no less than forced surrender of raisins—constitutes a physical taking of personal property requiring just compensation.

b. Axial Basin

The 145 MW Axial Basin generating facility, located near the Craig Generating Station, relies on much of the same transmission infrastructure. There is insufficient transmission capacity to move all electricity generated by the three Craig units and Axial Basin to the broader power grid. The Order thus constitutes appropriation of Tri-State's transmission infrastructure (including transmission infrastructure allocated to Axial Basin), a clear physical intrusion. This transmission limitation may

[19] Diverting this coal will require Petitioners to purchase replacement fuel at uncertain cost, imposing an additional, uncompensated expenditure that independently constitutes a taking. Use of an alternative source of supply not only results in additional costs, but also requires Petitioners to negotiate new contracts and alter operations at the Craig facility to account for variances between the physical qualities of different coal supplies. Meanwhile, using coal with different physical qualities could also require expensive and time-consuming modification of one or more Craig Units to allow such coal to be burned.

trigger additional physical intrusion, as ensuring sufficient transmission capacity for Craig Unit 1's compliance with the Order may require curtailment of one or more other generation facilities (especially when the system is operating near capacity).

c. Physical Changes to Craig Unit 1

Ongoing operations at Craig Unit 1 will require continual maintenance and staffing readiness, with further equipment failures requiring repair and staffing (including overtime). Compelling a property owner to make improvements to their property constitutes a physical taking when the mandated improvement benefits others—particularly the public at large—but do not benefit the property owner. "Put in general terms, government may not force a landowner to make an improvement that, while valuable to others, is useless to him" without it constituting a compensable taking. *Furey v. City of Sacramento*, 780 F.2d 1448, 1454 (9th Cir. 1986) (discussing *Norwood v. Baker*, 172 U.S. 269 (1898) and *Myles Salt Co. v. Bd. of Comm'rs*, 239 U.S. 478 (1916)), *abrogated on other grounds, Cumbre Inc. v. State Compensation Ins. Fund*, 403 F. App'x 272 (9th Cir. 2010). The Order requires Petitioners to continue to maintain and operate Craig Unit 1, and to replace equipment and material, even though they had planned to imminently retire the unit for good and Unit 1 is not needed to serve the reliability needs of their respective systems. This is the kind of physical taking described in *Furey*.

B. The Order Constitutes a Regulatory Taking

In addition to being a *per se* physical taking, the Order constitutes a regulatory taking. Regulatory takings occur where the government "imposes regulations that restrict an owner's ability to use his own property" but goes too far. *Cedar Point*

Nursery, 594 U.S. at 148. The property rights implicated by the Takings Clause can include contract rights, *see Lynch v. United States*, 292 U.S. 571, 579 (1934), and government-created entitlements with economic value, *Ruckelshaus*, 467 U.S. at 1001–1004 (trade secrets constituted property for takings purposes). When evaluating whether a regulatory burden constitutes a taking, courts look to the test established in *Penn Cent. Transp. Co. v. N.Y.C.*, 438 U.S. 104, 124 (1978), which evaluates regulatory takings based on: (1) the regulation's economic impact; (2) its interference with reasonable investment-backed expectations; and (3) the character of the government action. The Order constitutes a regulatory taking under this analysis.

1. Economic Impact

In requiring Petitioners to "take all measures necessary to ensure that Craig Unit 1 is available to operate," the Order places a heavy economic burden on Petitioners. Petitioners incur various operations and maintenance costs to ensure Craig Unit 1 is ready and able to operate at SPP's direction. Moreover, because of limited capacity over common transmission facilities, dispatching Craig Unit 1 while the other Craig Units are operating can impede SPP's ability to dispatch the nearby Axial Basin generating facility. This, in turn, prevents Petitioners from gaining the benefit of a margin on more economic resources, including renewable energy credits (which themselves have tangible economic value).

2. Investment-Backed Expectations

"[T]he regulatory regime in place at the time the claimant acquires the property at issue helps to shape the reasonableness of [investment-backed]

expectations." *Palazzolo v. Rhode Island*, 533 U.S. 606, 633 (2001) (O'Connor, J., concurring). Where a change in regulation dramatically disrupts the economic basis for a property owner's choices, it constitutes unreasonable interference with reasonable investment-backed expectations. *See Petworth Holdings, LLC v. Bowser*, 308 F. Supp. 3d 347, 356–58 (D.C. Cir. 2018). An explicit government guarantee forms the basis of a reasonable investment-backed expectation. *See Ruckelshaus*, 467 U.S. at 1011.

The Order disrupts Petitioners' reasonable investment-backed expectations on several fronts. DOE's use of Section 202(c) authority to address potential long-term shortages or grid reliability problems is a substantial and novel change to prior uses of Section 202(c) emergency authority.[20] The Order fundamentally alters DOE's longstanding approach in a novel, untested way that could not be predicted from DOE's previous actions, and certainly not when Petitioners decided a decade ago to retire Craig Unit 1 in 2025. Petitioners could not have fairly anticipated DOE's novel approach to Section 202(c) when it engaged in business planning and made investment decisions; thus, the Order upsets Petitioners' reasonable expectations. Diverting coal from Craig Unit 1 to comply with the Order, moreover, depletes Craig Unit 2 and 3's fuel reserves and hinders Petitioners' right and ability to freely use those facilities consistent with their investment-backed expectations.[21]

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[20] *Rolsma* (2024) at 802–09, 839–46 (discussing paucity of involuntary Section 202(c) orders since WW2).

[21] The Order also upsets Petitioners' delicate contractual relationships. Even if Section 202(c) provides protection from enforcement action by Colorado under "environmental" laws, disruption to these longstanding relationships disturbs Petitioners' ability to manage risk,

Finally, the electrical generation and transmission industry operates on a long time horizon. Craig Unit 1's planned closure was announced a decade ago, and numerous steps, such as deferring maintenance, reducing staffing, and redirecting capital expenditures, have been undertaken since. Disruption of these long-term plans upsets Petitioners' reasonable investment-backed expectations. The seizure of a facility eight years in advance of a potential emergency upsets a reasonable expectation that long-term resource planning will be the mechanism by which utilities address resource adequacy needs.

3. Character of the Taking

The character of a governmental action is defined by "the purpose and importance of the public interest underlying [the] regulatory imposition, by obligating the court to inquire into the degree of harm created by the claimant's prohibited activity, its social value and location, and the ease with which any harm stemming from it could be prevented." *Maritrans, Inc. v. United States*, 342 F.3d 1344, 1356 (Fed. Cir. 2003) (internal quotation and citation omitted). "A 'taking' may more readily be found when the interference with property can be characterized as a physical invasion by government . . . than when interference arises from some public program adjusting the benefits and burdens of economic life to promote the common good." *Penn Cent.*, 438 U.S. at 124 (citations omitted).

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engage in long-term planning, and maintain their reputations as reliable counterparties. Petitioners have made commitments to stakeholders and planned their businesses around complying with existing environmental laws, which form part of their reasonable investment-backed expectations.

The character of the Order's action further aligns with a regulatory taking. As discussed above in Section (I)(A), the Order effectively commandeers Craig Unit 1, its fuel, the potential dispatch of the nearby Axial Basin facility, and related infrastructure owned by Petitioners. It places Craig Unit 1 under the control of SPP, a non-governmental actor, and requires Petitioners to comply with "all orders" that SPP issues "related to the availability and dispatch of Craig Unit 1." Order at 7. The Order does not merely adjust the benefits and burdens of economic life, but rather directs operational control for a public reliability aim that could—and should—be solved through other means, and by other electrical utilities.

C. Just Compensation

The Takings Clause provides that "private property [shall not] be taken for public use, without just compensation." U.S. Const. amend. V. Whether compensation is "just" is measured by relation "both to an owner whose property is taken and to the public that must pay the bill[.]" *United States v. Commodities Trading Corp.*, 339 U.S. 121, 123 (1950). "The owner's loss is measured by the extent to which governmental action has deprived him of an interest in property." *Wheeler v. City of Pleasant Grove*, 833 F.2d 267, 270 (11th Cir. 1987). Petitioners cannot obtain constitutionally sufficient compensation for the costs the Order imposes for several reasons.

First, SPP's existing market structures do not assure Petitioners they can recover both their variable and fixed costs of continued operation of Craig Unit 1. Under SPP's existing market structure, generators like Petitioners participate by bidding their output into SPP's real-time and day-ahead energy and ancillary services

market. SPP's markets assure generators recovery of only their marginal, variable costs—not fixed costs.[22] As a long lead-time reliability resource, Craig Unit 1 is offered for selection within a multi-day resource assessment. In the event SPP selects the resource for reliability purposes, the resource is compensated for energy costs. SPP does not operate a mandatory all-resource capacity market, a mechanism by which generators recover their non-variable (fixed) costs.[23] And, in any event, the Order instructs that Craig Unit 1 "shall not be considered a capacity resource[,]" Order at 7.

Second, while Section 202(c) and its implementing regulations suggest recovery may be possible through FERC rate-making processes, that suggestion is not a promise of constitutional recovery.[24] The scope of the purported emergency, covering the entire WECC–Rocky Mountain region, is broader than just SPP's market. Public Service Company of Colorado's (PSCo) Balancing Authority Area, for example, falls within the WECC–Rocky Mountain region identified as experiencing

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[22] *See* Market Protocols—SPP Integrated Marketplace, at 39 ("SPP committed Resources are assured recovery of their Start-Up Offer, No-Load Offer and actual incremental Energy costs as defined in the Energy Offer Curve subject to certain eligibility criteria[.]").

[23] *See* Federal Energy Regulatory Commission, Office of Energy Policy and Innovation, *Energy Primer: A Handbook for Energy Market* Basics 72 ("[C]apacity markets are intended to provide more certainty for investment in new capacity resources while including an opportunity for all resources to recover their fixed costs over time.").

[24] The terms of the Order, moreover, could have substantive impact on Tri-State's ability to make energy sales at market-based rates through authority granted to it by FERC. *See, e.g.*, *Tri-State Generation and Transmission Ass'n,* 170 FERC ¶ 61,220, at PP 1, 22 and ordering para. (A) (2020) (generally providing Tri-State with authorization to transact at market-based rates). The circumstances are analogous for Platte River. Platte River also makes energy sales at market rates, but, as a government utility exempt under FPA Section 201(f), Platte River does not need market-based rate authority from FERC.

the "emergency" and thus PSCo presumably benefits from Craig Unit 1's continued operations, but PSCo does not participate in SPP, the mechanism for potential compensation identified in the Order. DOE sets forth no mechanism for navigating these complexities, much less an assurance of just recovery notwithstanding these issues; at minimum DOE should clarify the entities from which it intends to provide Petitioners the right to seek recovery.[25] And conflating recovery from SPP with constitutional just compensation is particularly inappropriate here because recovery from SPP, of which Petitioners are a part, means that "cost recovery" would in significant part come from the pockets of ***Petitioners themselves***.[26] The Takings Clause does not permit the federal government to appropriate control and use of property while leaving the owner without a mechanism to obtain just compensation from the government itself.

[25] As such, Petitioners request clarification of which "ratepayers" DOE is referring to in the Order, such as SPP ratepayers, all ratepayers within the WECC–Rocky Mountain region, or ratepayers for all co-owners of Craig Unit 1.

[26] For example, Tri-State comprises approximately 52% of the SPP West load but owns only 24% of Craig Unit 1. Additionally, there are co-owners of Craig Unit 1 that are not participants in SPP, who will bear costs without any apparent mechanism of recovery through SPP. If costs are allocated in proportion to load, and recovery in proportion to ownership, Tri-State and other co-owners who do not participate in SPP stand to lose. Routing recovery through SPP may obligate these co-owners to fund more than half of the costs imposed by the Order, effectively compelling them to subsidize purported reliability benefits for others without any showing that Craig Unit 1's co-owners required the Unit's continued operation to address any identified resource shortfall. *See* Tri-State 2026 Resource Adequacy Annual Report (2026), https://tristate.coop/sites/default/files/PDF/resourceplan/Resource%20Adequacy_2026.pdf (showing excess resources in Tri-State's footprint through 2035); Platte River Power Authority Resource Adequacy Report 2025 (2025), https://prpa.org/wp-content/uploads/2025/04/PRPA_RA2025_-signed.pdf (showing excess resources in Platte River's footprint through 2030).

Petitioners raised these problems in their initial request for rehearing but the Order fails to resolve them. DOE's refusal to bridge this gap is especially problematic given that the renewed Order altered the geographic framing of the asserted emergency. Having adjusted the relevant assessment area and introduced new evidence, DOE had ample opportunity to explain how Petitioners could obtain just compensation or to offer just compensation. DOE failed to do so. This is no small matter. If Petitioners must continue to dispatch Craig Unit 1, as the unit has in the past, for the entire emergency period until 2034, costs could exceed millions in operating and maintenance costs, exclusive of fuel costs.

Moreover, even if Petitioners can and do recover some costs through this process, it is still not *just compensation* within the meaning of the Takings Clause. "[O]nce the government executes a taking, the Constitution does not permit it to shift the public's burden of just compensation to third parties. When property is taken for public use under the Fifth Amendment, the public—and not specific individuals or groups at the order of the government—must pay." *Carson Harbor Village, Ltd. v. City of Carson*, 353 F.3d 824, 831 (9th Cir. 2004) (O'Scannlain, J., concurring); *see also U.S. Bank, Nat'l Assoc. v. SFR Invests. Pool 1, LLC*, Case No. 15-cv-00287-APG-GWF, 2016 WL 1248704, at *5 (D. Nev. Mar. 28, 2016) ("[A] takings claim requires just compensation from the government, not from a private third party."); *Baker v. City of McKinney*, 608 F. Supp. 3d 457, 465–67 (E.D. Tex. 2022) (plaintiff was entitled to full compensation for a taking by police even though she obtained additional money from donations).

This is particularly true where, as here, at least some of Petitioners' relief will come from Tri-State's members and Platte River's ratepayers, even if FERC orders some level of cost recovery.[27] DOE cannot simply transfer the constitutional obligation to provide just compensation onto private parties—including, here, rural communities and the residents of four small Colorado municipalities—through regulatory mandates without satisfying its own Takings Clause obligations.

II. THE ORDER DISRUPTS PETITIONERS' RELIABILITY PLAN AND FAILS TO ACCOUNT FOR VIABLE ALTERNATIVES

Separate from whether DOE must compensate Petitioners for the impact of the Order on their property and operations, the Order suffers from statutory and constitutional defects.

First, the Order fails to identify an emergency that meets the requirements of Section 202(c), or that is addressable by keeping Craig Unit 1 open. The issues articulated by the Order are fundamentally mismatched—temporally and geographically—with the Order's methods. Forcing Craig Unit 1 to remain open is counterproductive, disrupting a considered resource planning effort aimed at addressing the very concerns DOE raises in the Order. This analytical failure renders the Order arbitrary and capricious.

[27] As noted in the Order, a significant driver of the growth in the demand for energy nationwide is data center demand. *See* Order at 5. To the extent the alleged emergency has been caused by the demands of data centers, shifting the costs of Craig Unit 1 onto Petitioners and their ratepayers is contrary to President Trump's pledge to protect ratepayers from these effects. *See* Ratepayer Protection Pledge, Proclamation No. 11014, 91 F.R. 11439 (Mar. 4, 2026).

Second, the rote invocation of an "emergency" does not waive Petitioners' constitutional due process rights to pre-deprivation notice and a hearing. The materials relied upon in the Order demonstrate that the alleged resource-adequacy concerns are not sudden or unforeseen but instead involve long-term conditions projected to arise years in the future. And where, as here, DOE had ample time to deliberate—and was already informed in Petitioners' prior rehearing request that its proposed action raised serious due process concerns—the asserted need to address an emergency eight years in the future does not excuse DOE's failure to provide notice and an opportunity for Petitioners to be heard before imposing the Order.

Third, the Order does not meet the requirements of Section 202(c). It does not limit the Orders to a remedy necessary to address the emergency, and it does not consider reasonable alternatives as required by Section 202(c) (including Petitioners' carefully calibrated reliability planning, using both thermal and renewable resources based on findings supported by objective, industry-leading forecasting methods). And *fourth*, the Order is inconsistent with the FPA's objectives. The Order is, therefore, contrary to law and arbitrary and capricious.[28]

[28] As DOE is aware, Petitioners have already taken and will continue to take steps to comply with the Order. This includes incurring compensable costs and expenses. Although the Order is improper under Section 202(c), Petitioners are nonetheless entitled to cost recovery under Section 202(c) and as a compensable taking. Petitioners note that Section 202(c) is an emergency provision, and, for that reason, recovery pursuant to its terms should not turn on an ultimate determination of the lawfulness of the Order. Further, the Order provided notice to all potential ratepayers that rights to recovery would accrue to Petitioners (and the other co-owners) beginning on December 30, 2025. To bar Petitioners from recovering these already-incurred costs would be inconsistent with Section 202(c)'s purpose to respond to emergency conditions and would violate constitutional protections. Petitioners' position is based on currently available facts and information. Petitioners reserve all rights.

A. The Order Describes Speculative Energy Shortfalls in 2034, and Therefore Does Not Establish the Existence of an Emergency Addressed by Requiring Continued Operation and Dispatch of Craig Unit 1

Section 202(c)(1) provides that DOE may issue an order when it determines "an emergency exists," and that the emergency was caused by "a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes[.]" 16 U.S.C. § 824a(c)(1). DOE's regulations define an emergency as an "unexpected inadequate supply of electric energy" and envision use of Section 202(c) to address a "specific inadequate power supply situation." 10 C.F.R. § 205.371 (2026). These regulations acknowledge that "inadequate planning or the failure to construct necessary facilities" may lead to an emergency—but also indicate that 202(c)'s role is to provide short-term relief. As DOE explained in its rulemaking:

> The DOE does not intend these regulations to replace prudent utility planning and system expansion. This intent has been reinforced in the final rule by expanding the "Definition of Emergency" to indicate that, while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.[29]

As DOE admits, Section 202(c) is focused on short-term problems with specific solutions. *Accord* 10 C.F.R. § 205.371 (where inadequate planning causes an emergency, DOE expects that "the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a

[29] Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39984 (Aug. 6, 1981).

continuing emergency order is not needed"). DOE's longstanding regulations confirm that Section 202(c) authority is not intended as a substitute for long-term planning or resource development, but as a temporary tool to address unexpected shortfalls—the opposite of the long-horizon concerns cited in the Order.[30]

A speculative "emergency" occurring eight years or more in the future is not a "specific inadequate power supply situation" as required by DOE's regulations for a Section 202(c) order, nor is it an example of a "sudden increase in the demand for electric energy." Structural changes in electricity markets are precisely the kind of issue addressed by long-term collaborative planning by utilities, communities, and state governments. And while the Order alludes to potential future shortages in the WECC–Rocky Mountain region, it fails to specify where within the WECC–Rocky Mountain area a shortage is expected to arise, how Craig Unit 1's output would be deliverable to the locations of concern, or why existing reserves, imports, or market mechanisms would be inadequate to address the risk. The Order is therefore contrary to law and arbitrary and capricious.

1. Keeping Craig Unit 1 Open Does Not Address Long-Term Concerns

DOE rests the Order on concerns that, as mentioned *supra*, are predicted to occur at least 31 90-day renewal cycles in the future, yet the Order requires Petitioners to take action now. To justify the Order, DOE relies principally on: (1) NERC's 2025 LTRA; (2) the 2025 WECC Western Assessment of Resource

[30] Notably, DOE has not attempted to update these definitions to conform the agency's defined causes of an "emergency" with the novel approach of its Section 202(c) orders.

Adequacy; and (3) expressions of concern by two Colorado Public Utilities Commissioners concerning the ability of a separate utility, PSCo, to meet summer 2026 loads. Order at 4–5. None of these justifications rationally support the Order, let alone establish that requiring Craig Unit 1 to operate now will address the asserted emergency.

The 2025 LTRA expressly provides—and DOE acknowledges—that there is no elevated risk for energy shortfalls over the next five years. As the LTRA shows, actual reserve margin and planning reserve margin are above the reference margin level through 2033, and NERC anticipates ***no*** loss-of-load hours (LOLH) through 2029 for the WECC-Rocky Mountain region. To the contrary, the materials DOE relies on show that in the WECC-Rocky Mountain subregion, the number of projected LOLHs will remain comfortably below DOE's benchmark for reliability over the next decade (so long as planned resource additions roughly approximate current expectations).[31] Indeed, even if actual resource additions fall *well* below projections, it will be more than six years until the number of LOLH hours in a year *may* exceed DOE's own standards.[32] Put plainly, the WECC-Rocky Mountain Region is expected to meet

[31] WECC's analysis indicates that if 85% of planned generation is built, there will be only four LOLH hours in the Rocky Mountain region in the next 10 years (20 LOLHs below DOE's threshold). *See 2025 Western Assessment Supplemental Information*, WECC [https://feature.wecc.org/warasupplemental/index.html] (last visited April 29, 2026); U.S. Dep't of Energy, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid 4 (July 2025), https://www.energy.gov/ sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY %207%29.pdf.

[32] Even in a scenario where only 67% of currently planned generation is built, it is not until 2032 that WECC projects a possibility of more than 2.4 LOLH hours in a single year. *See 2025 Western Assessment Supplemental Information*, WECC ([https://feature.wecc.org/warasupplemental/index.html] (last visited April 29, 2026).

DOE's reliability benchmark for years to come without Craig 1. The region is projected to add sufficient generating capacity to meet demand, and NERC does not expect any hours—now or in the next several years—when there will not be enough electricity to serve customers. The evidence DOE relies upon confirms that no resource adequacy concerns are likely to appear in the region until well into the 2030s.

Keeping Craig Unit 1 online ***now*** simply does not meet the terms of an emergency predicated on potential resource adequacy issues eight or more years in the future, particularly given that as Craig Unit 1's operations are further extended past its intended lifespan, it is likely to experience more and longer periods of outage. Moreover, given that operating Craig Unit 1 ***now*** depletes the fuel stockpile for Craig Units 2 and 3, the Order's actions today may ***create*** reliability concerns that would not exist were Craig Unit 1 to shut down as originally scheduled.[33]

2. Keeping Craig Unit 1 Open Does Not Best Address Concerns in DOE's Targeted Regions

The Order also cites reliability concerns specifically for the WECC Basin and Northwest subregions on one hand, and for the United States as a whole on the other. Order at 3–5. Even if those speculative future conditions could constitute an

[33] DOE also predicates its emergency in part on the WECC-Rocky Mountain subregion's alleged "challenges from an aging thermal resource fleet, which can lead to unplanned outages, exacerbated by supply chain issues, and vendor availability." Order at 3 (citation omitted). DOE's citation, however, is incorrect: the 2025 LTRA does not cite the age of the subregion's thermal fleet as an operational and planning issue. Rather, the LTRA identifies supply chain issues, unplanned discovery work, and vendor availability for repairs at both thermal and hydropower sites as a concern for the region. 2025 LTRA at 161. Moreover, forcing Craig Unit 1 to continue operating to address projected shortfalls in 2034, when it would be 54 years old, only exacerbates concerns about reliance on aging resources.

"emergency" under Section 202(c)—they cannot—Craig Unit 1 is located in the WECC-Rocky Mountain region, and its continued operations cannot reasonably be expected to resolve reliability concerns (also years away) in far-flung locations. As noted, over a dozen of Tri-State's rate-paying Utility Members in New Mexico and Nebraska are located outside of the WECC-Rocky Mountain emergency area, but as owners of Tri-State remain obligated to pay for the costs of compliance despite no emergency being identified in the regions they serve.

DOE's failure to bridge this gap is especially problematic given that the renewed Order altered the geographic framing of the asserted emergency. Having adjusted the relevant assessment area, DOE had ample opportunity to explain how Craig Unit 1 is best suited to address locations of concern, yet it did not.

B. The Order is Procedurally Inadequate on Both Constitutional and Statutory Grounds

Agencies must abide by both constitutional and statutory procedural safeguards before they act. The Fifth Amendment's Due Process Clause guarantees that no person shall be "deprived of life, liberty or property" by the federal government "without due process of law." U.S. Const. amend. V. At its core, due process requires notice and an opportunity to be heard before the government takes action affecting protected interests. *Memphis Light, Gas & Water Division v. Craft*, 436 U.S. 1, 19 (1978). This principle applies across regulatory regimes where hearings are generally required before agencies impose obligations or alter rights. Similarly, where a statute creates specific procedural requirements before it can take action, failure to follow these requirements renders the agency action arbitrary and

capricious. *See Safari Club International v. Zinke*, 878 F.3d 316, 325 (D.C. Cir. 2017) ("A disputed action also may be set aside as arbitrary and capricious if the agency has acted 'without observance of procedure required by law.'") (citing 5 U.S.C. § 706(2)(D)).

The Order violates both constitutional due process and the procedural requirements of Section 202(c)(4)(B)'s consultation and condition-incorporation requirements. These procedural failings render the Order unlawful.

1. The Order Violates Petitioners' Constitutional Due Process Rights

Under the FPA, most Commission (*i.e.*, FERC or DOE) actions—such as rate changes or interconnection orders—cannot take effect without a prior hearing. *See generally* 16 U.S.C. §§ 824a(b), 824a(e), 824a-1(a), 824a-3(f), 824a-4, 824b(a)(4), 824c(b), 824d, 824e, 824f, 824i(b), 824j, 824j-1, 824k, 824m, 824o, and 824p. Section 202(c) orders are unusual in that they may be issued without any prior hearing, reflecting their purpose as a short-term emergency tool meant to address fast-moving and unexpected situations. *See Fuentes v. Shevin*, 407 U.S. 67, 90–91 (1972) (holding that to justify postponing notice and opportunity for a hearing before deprivation of a property interest on basis of an "extraordinary situation," the situation must be "truly unusual.").

However, "[t]here is a relation between the kind of emergency and nature of the solution." *Pa. Gas & Water Co.*, 427 F.2d at 577. Where a hearing is feasible, its absence deprives Petitioners of due process. *See South Allegheny Pittsburgh Restaurant Enterprises, LLC v. City of Pittsburgh*, 806 Fed. Appx. 134, 139–41 (3d

Cir. 2020) (holding that the manifest lack of a qualifying emergency meant that order shutting down under-21 nightclub violated plaintiff's procedural due process rights); *Chalkboard, Inc. v. Brandt*, 902 F.2d 1375 (9th Cir. 1989) (suspension of daycare employees' licenses without pre-deprivation process because of asserted categorical emergency violated procedural due process rights); *Miller v. Campbell Cnty.*, 945 F.2d 348, 353 (10th Cir. 1991) (finding emergency insufficient to avoid need for pre-deprivation hearing when two months elapsed between notice that plaintiff's homes were uninhabitable and date of planned evacuation, but concluding that sufficient pre-deprivation hearing opportunities had occurred).

The Order's emergency does not rest on an urgent and immediate need for additional generation to address a specific incident or event such as unusually extreme weather. Rather, the Order's purported emergency is based on broader concerns about the sufficiency of generation capacity and reliability in the WECC–Rocky Mountain assessment area over time and in the future. Because the Order does not demonstrate an immediate crisis, it cannot justify dispensing with the pre-deprivation hearing requirement. Petitioners, however, have received no such process. Thus, they were deprived of their constitutional right to notice and a hearing before the Order came into effect.

Petitioners identified this Constitutional deficiency in their prior request for rehearing. But rather than accord Petitioners due process, DOE simply issued this new Order with no additional process and with no explanation for why no process was required. Even if the initial order could be defended as emergent, the second cannot.

Having received notice of the due-process defect and having had ample time to address it, DOE's decision to reissue a materially identical order without any procedural safeguard constitutes a discrete constitutional violation and is itself arbitrary and capricious.

2. DOE's Failure to Engage with the EPA Renders the Order Invalid

Section 202(c)(4)(B) mandates that DOE "consult with the primary Federal agency with expertise in the environmental interest protected by" the laws or regulations waived by a renewed order and include any conditions mandated by that agency in the order, which must be "made available to the public." 16 U.S.C. § 824a(c)(4)(B). Similarly, while DOE "may exclude such a condition from the renewed or reissued order if it determines that such condition would prevent the order from adequately addressing the emergency necessitating such order[,]" DOE must provide a public explanation of this lack of condition in the order. *Id.*

This consultation requirement is both mandatory and substantive. After all, Congress empowered DOE to take extraordinary action by extending a Section 202(c) order only *after* DOE has been made aware of the environmental impacts of renewing an order. *Cf. Center for Biological Diversity v. Zeldin*, --- F.4th ---, 2026 WL 850257, at *17–18 (D.C. Cir. Mar. 27, 2026) (holding that programmatic consultation did not alleviate burden of EPA to directly consult with National Marine Fisheries Service under Endangered Species Act because planned action could affect species under NMFS's jurisdiction). The FPA's direction to "consult" with relevant stakeholders obligates DOE to engage in a "meaningful exchange of information[.]" *California*

Wilderness Coal. v. U.S. Dep't of Energy, 631 F.3d 1072, 1086 (9th Cir. 2011) (finding DOE failed to "consult" with the states as required by FPA Section 216).[34]

DOE does not identify ***any*** agency it consulted in promulgating the Order. At the very least, EPA, the entity that administers the Clean Air Act and other statutes most directly relevant to Craig Unit 1 and which approved Colorado's Regional Haze State Implementation Plan (of which the closure of Craig Unit 1 was a part), should have been consulted. The Order, however, does not describe any consultation with EPA and thus contains no indication that DOE complied with an explicit statutory element of a lawfully renewed Section 202(c) order. That alone renders it unlawful. And the defect is not just procedural, but substantive. Meaningful consultation with the EPA, for instance, would inform DOE about the incompatibility of keeping Craig Unit 1 open with Colorado's federally-approved emissions plans and the impact of regulatory uncertainty on utilities' long-term planning around the country, as well as inform how DOE balances different options, and help identify the best alternative as required by Section 202(c).

C. The Order Failed to Limit Emergency Relief to What Is Necessary to Address the Asserted Emergency and Did Not Consider Reasonable Alternatives

Section 202(c) authorizes only those extraordinary measures that are necessary to resolve the emergency at hand, and it requires the Secretary to exercise

[34] The District Court for the District of Columbia recently held that a "late Friday afternoon, three-sentence email exchange between staffers" was insufficient to qualify as "consulting" another agency. *Miot v. Trump*, No. 25-cv-02471 (ACR), 2026 WL 266413, at *22 (D.D.C. Feb. 2, 2026), *cert. granted before judgment*, No. 25-1084, 2026 WL 731087 (U.S. Mar. 16, 2026).

judgment in selecting the course of action that will best meet that emergency and serve the public interest. 16 U.S.C. § 824a(c)(1)–(2). Those requirements impose meaningful limits on DOE's authority, including an obligation to confine any order to what is actually required to address the asserted emergency. The Order fails this threshold requirement. Rather than identifying a specific, imminent reliability problem that necessitates continued operation of Craig Unit 1, DOE imposes a sweeping mandate—of significant scope, duration, and operational rigidity—without explaining why that measure is necessary to address the conditions it cites. By failing to limit emergency relief to what is demonstrably required, the Order exceeds the narrow authority Section 202(c) confers and is arbitrary and capricious.

Lack of necessity is confirmed by DOE's failure to consider reasonable alternatives. Section 202(c) requires the Secretary to exercise "judgment" and select only those measures that "will *best* meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1) (emphasis added). Implicit in this mandate is the recognition that alternatives be considered and ruled out. Having been on notice—both in Petitioners' prior rehearing request and in the intervening months—that alternatives existed, DOE's failure to evaluate them in reissuing the Order independently renders the decision arbitrary and capricious.

DOE should have conducted and disclosed an analysis showing why the path selected is the "best" course forward, particularly in light of the potential 2034 time-horizon of the asserted emergency. *See Michigan v. EPA*, 576 U.S. 743, 753 (2015) (holding that "reasonable regulation ordinarily requires paying attention to the

advantages and the disadvantages of agency decisions"). This is consistent with the emergency nature of the powers contained in Section 202(c), which should not be exercised where "alternatives offered a more confined solution" to the emergency at issue.[35] *Pa. Gas & Water Co.*, 427 F.2d at 577 (considering analogous powers under the Natural Gas Act); *see also Farmers Union Cent. Exchange, Inc. v. FERC*, 734 F.2d 1486, 1511 (D.C. Cir. 1984) ("It is well established that an agency has a duty to consider reasonable alternatives to its chosen policy, and to give a reasoned explanation for its rejection of such alternatives.") (citation and footnote omitted).

As with DOE's first order, the Order reflects no consideration of alternatives, let alone justification for mandating that Craig Unit 1 remain active over other options, and is thus contrary to law and arbitrary and capricious. This failure is especially indefensible here because Petitioners specifically identified alternative approaches in their prior request for rehearing.[36] And an "emergency" occurring eight or more years from now can be solved by any number of means: more generation, more efficient use of existing generation, load flexibility, etc. DOE nevertheless

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[35] DOE regulations for utilities applying for a Section 202(c) order to override environmental regulations require the utility to provide extensive information related to operations and alternative courses of action. *See* 10 C.F.R. § 205.373(g)–(i) (mandating that applicants provide information concerning "conservation or load reduction actions," "efforts . . . to obtain additional power through voluntary means," and "[a] listing of proposed sources and amounts of power necessary from each source to alleviate the emergency and a listing of any other 'entities' that may be directly affected by the requested order.").

[36] Request for Clarification and Rehearing of Order No. 202-25-14 at 31. Petitioners identified the possible alternatives of: (1) DOE and/or FERC "proceeding through the rulemaking process pursuant to section 403 of the Department of Energy Organization Act, 42 U.S.C. § 7173, to devise a plan to ensure reliability through a more fulsome, consultative process[;]" and (2) DOE "evaluat[ing] whether it had authority to take proactive action to insure that 'new resources' in the region are not 'significantly delayed.'"

reissued a materially identical order months later without assessing those alternatives or explaining why they were inadequate. Whatever urgency DOE might initially claim, it cannot excuse reissuing a materially identical order without engaging with the alternative approaches identified by Petitioners and explaining why mandating that Craig Unit 1 remain active is the "best" measure to address this long-term reliability concern across the region described in the Order.[37]

Moreover, the long-term nature of the "emergency" articulated by DOE reinforces the need to consider alternatives and broadens the scope of what must be considered. While the "menu" of emergency responses to a sudden and unexpected crisis caused by natural disaster may be limited, the menu of policy options to address reliability concerns eight years in the future is not.

Similarly, DOE's need to consider alternatives is particularly important given Craig Unit 1's status. Craig Unit 1 is an older, uneconomic unit. Due to its long-planned retirement, Craig Unit 1 has experienced years of prudently deferred maintenance and therefore faces particularly high costs to restore and maintain operations compared to possible alternatives. The Order further fails to consider how mandating Craig Unit 1's continued operation interferes with Petitioners' ability to invest in or use other, more economic generation capacity and therefore undermines the very ends that it purports to advance. As previously discussed, the Axial Basin

[37] That Craig Unit 1 has been dispatched since Order No. 202-25-14 was issued does not demonstrate that keeping it in operation and available for dispatch either responds to DOE's asserted "emergency" in any way, or that it is the *best* such response when alternatives are considered (none were). SPP's decision to call on the tools in its toolbox is unrelated to whether DOE's decision to mandate that Petitioners place the tool in its toolbox is reasonable or justified by its Order.

generating facility relies on the same transmission infrastructure as the Craig units. That infrastructure is already congested; when all three Craig units are operating, Craig Unit 1's continued operation could interfere with the ability of new alternatives like Axial Basin to provide economic power to the grid.

In the absence of such consideration, and disclosure of a valid rationale, Petitioners and the public "cannot weigh the merits of an agency decision nor compare it to other alternative actions[.]" *Rocky Mountain Wild v. Bernhardt*, 506 F. Supp. 3d 1169, 1187 (D. Utah 2020). The Order does not discuss why Craig Unit 1's continued operation was selected as the "best" solution to the described conditions, or if alternatives were considered, what those alternatives were, and why any considered alternatives were discarded. Thus, it is contrary to law and an arbitrary and capricious exercise of agency authority.

D. The Order Improperly Usurps the Role of State and Local Governments, Utilities, and Markets in Resource Adequacy Planning

Keeping an aging coal plant online, 90 days at a time, cannot resolve resource shortfalls eight years from now. But developing and implementing a plan to build more generation, and executing on that plan, can. This is what Petitioners—along with other utilities and state and local regulators—aim to do, and are doing. Yet, the Order interferes with these efforts: DOE's approach disrupts a complex ecosystem that includes utility-led resource planning and various layers of supervision and market mechanisms. The Order disrupts this process and makes determining and proceeding with the most efficient and effective solution more difficult.

The FPA imposes an express jurisdictional limit on the exercise of Section 202(c). FPA Section 201(b)(1), 16 U.S.C.A. § 824(b)(1), states that FERC—and, here, DOE exercising FERC's authority—has no jurisdiction "over facilities used for the generation of electric energy" unless such jurisdiction is specifically provided for. The "States' reserved authority[,]" *Hughes v. Talen Energy Marketing, LLC*, 578 U.S. 150 (2016), includes the "[n]eed for new power facilities, their economic feasibility, and rates and services," all of which "are areas that have been characteristically governed by the States." *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983). [38]

Under this framework, deciding whether Craig Unit 1 should remain operational belongs to its owners and subject to oversight by state governmental units. This reflects, among other things, the unique privileges and obligations of public utilities. *See Jackson v. Metro. Edison Co.*, 419 U.S. 345, 357 (1974) ("The nature of governmental regulation of private utilities is such that a utility may frequently be required by the state regulatory scheme to obtain approval for practices a business regulated in less detail would be free to institute without any approval from a regulatory body.").

[38] "Recognizing the careful balance that the FPA strikes between federal and state regulation" FERC recently found that "states retain exclusive authority over . . . the generation mix." *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61217, at P165 (2025). Long-term economic and planning decisions regarding Tri-State's resource mix had been approved by the State of Colorado through the 2020 and 2023 Energy Resource Plans. This jurisdictional division of responsibility and federal respect for state policymaking is also a policy of the FPA. *See Sierra Club v. FERC*, 145 F.4th 74, 81 (D.C. Cir. 2024) (respecting the role of state regulators); *NextEra Energy Res., LLC v. FERC*, 118 F.4th 361, 365 (D.C. Cir. 2024) ("[FERC] may regulate the transmission, but not the generation, of electricity[.]").

Utilities maintain the lead role in planning and constructing systems that ensure resource adequacy: both Tri-State and Platte River engage in reliability planning that balances system operational needs, cost and regulatory requirements.[39] In Colorado, the Colorado Public Utilities Commission (PUC) oversees resource adequacy planning for utilities under its jurisdiction, among other regulation and coordination of the electrical-generation sector.[40] Finally, other entities play a critical role. SPP, for instance, requires load-serving entities to maintain a certain level of Planning Reserve Margin capacity or face financial penalties, discouraging utilities from free-riding on other participants' efforts.[41]

For nearly a decade, Petitioners along with other co-owners have planned to retire Craig Unit 1 in line with resource adequacy planning. The Order attempts to supplant this process by substituting DOE's judgment for utilities' and Colorado's long-term resource planning decisions—all to address an "emergency" so diffuse that

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[39] Colorado's state government also plans around addressing shorter-term concerns. *See* , *e.g.*, Colo. Energy Office, Colorado Energy Assurance Emergency Plan (https://energyoffice.colorado.gov/climate-energy/colorado-energy-assurance-emergency-plan (last visited Apr. 29, 2026). The Colorado Energy Office (CEO) shares responsibility for energy assurance in the state with the Colorado PUC and state Division of Homeland Security and Emergency Management, with the PUC "primarily responsible for electric and natural gas energy emergencies." *Id.* To the extent the "emergency" is premised on shorter-term concerns, it arbitrarily fails to recognize the efforts made by utilities and state and local government to address them,

[40] *See generally* Colo. Dep't of Regulatory Agencies, PUC, Electric Resource Plans / Clean Energy Plan https://puc.colorado.gov/puc-home/energy-and-water/electric-resource-plans/clean-energy-plan (last visited April 29, 2026). The Colorado Energy Office also tracks resource adequacy in the state of Colorado. *See* C.R.S. 40-43-101 (requiring resource adequacy reports from Colorado utilities). The other states in which Tri-State operates also exercise varying degrees of oversight concerning Tri-State resources.

[41] SPP Open Access Transmission Tariff, Att. AA, § 14, https://www.spp.org/spp-documents-filings/?id=18162. SPP will begin imposing financial penalties in 2027.

its existence (or nonexistence) years from now is impossible to anticipate or cure. DOE's regulations recognize the distinction between the need to conduct planning and the existence of an emergency that results from inadequate planning. *See* 10 C.F.R. § 205.371 (an emergency may result "inadequate planning or the failure to construct necessary facilities" but such an emergency can be resolved through "firm arrangements"). The Order's failure to do so renders it contrary to law and arbitrary and capricious.

E. The Order is Inconsistent with the FPA's Statutory Objectives

Courts reject agency action as arbitrary and capricious if it is "inconsistent with the statutory mandate" or "frustrate[s] the policy that Congress sought to implement." *FEC v. Democratic Senatorial Campaign Comm.*, 454 U.S. 27, 32 (1981). The FPA was passed to advance various policy goals, including protecting consumers from "excessive rates and charges," *Xcel Energy Servs. Inc. v. FERC*, 815 F.3d 947, 952 (D.C. Cir. 2016) (citation omitted)); "maintaining competition to the maximum extent possible[,]" *Otter Tail Power Co. v. United States*, 410 U.S. 366, 374 (1973); and encouraging the "orderly development of plentiful supplies of electricity . . . at reasonable prices." *NAACP v. FPC*, 425 U.S. 662, 670 (1976).

The Order, by compelling an uneconomic, aging unit to remain operational well beyond its planned retirement, upends Petitioners' ability to plan their systems and act with confidence in a competitive marketplace. Because the Order is at odds with

the statutory objectives of the FPA, it is contrary to law and arbitrary and capricious.[42]

CONCLUSION

Petitioners are committed to providing reliable and affordable electricity to communities across Colorado and the Mountain West, and have planned accordingly by developing a resilient portfolio of generation resources. Petitioners seek to work constructively with DOE and other agencies to advance shared reliability and affordability goals. Actions that unsettle long-standing, state-approved planning processes, however, risk undermining those objectives and imposing unnecessary costs on the very consumers these processes are designed to protect.

For these reasons the Order cannot stand. It effects an uncompensated taking of Petitioners' property, denies them due process, and fails to meet Section 202(c)'s statutory requirements, including that DOE articulate a valid emergency and that DOE's chosen mandate "best meet" the stated emergency. Moreover, the Order does not address the points raised in Petitioners' first rehearing request. Petitioners urge DOE to reconsider the Order.

[42] As discussed *supra*, the Order similarly contradicts President Trump's pledge to protect ratepayers from the effects of DOE's Section 202(c) orders. *See* Proclamation No. 11014.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties below. Dated at Washington, D.C., this 29th day of April 2026.

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit NNN: NERC, 2026 Summer Resource Adequacy (May 2026)

2026 Summer Reliability Assessment

May 2026

RELIABILITY | RESILIENCE | SECURITY

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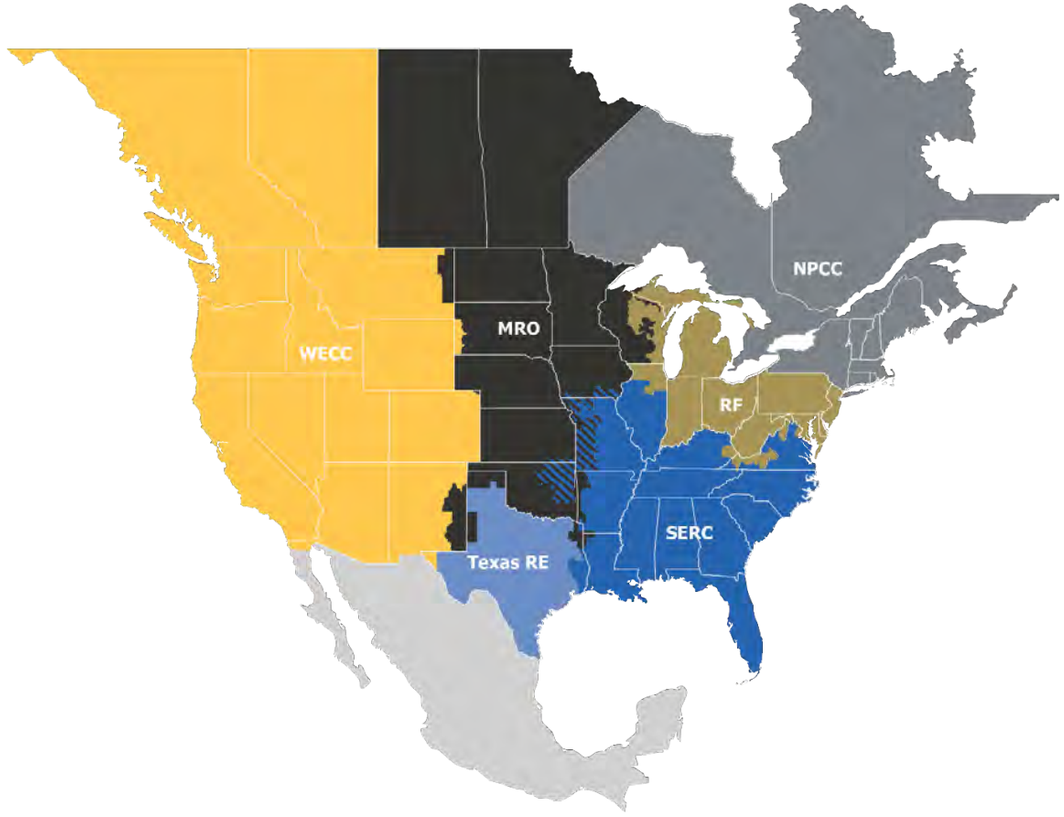
Preface

Electricity powers our modern life and is the bedrock of our economic wellbeing. The Electric Reliability Organization (ERO) Enterprise—comprised of NERC and the six Regional Entities—is firmly committed to assuring a highly reliable, resilient, and secure bulk power system (BPS) in North America. The ERO Enterprise enables collaborative engagement with industry, regulators, and stakeholders, embracing innovation and supporting the needs of nearly 400 million people.

RELIABILITY | RESILIENCE | SECURITY

POWERING TODAY. PROTECTING TOMORROW.

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Assessment

NERC's *2026 Summer Reliability Assessment* (SRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the SRA presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual SRA covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and risk hours as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2025 Long-Term Reliability Assessment* (LTRA), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

The 2026 Summer risk profile is marked by rising demand, significant generation growth in many areas, the prospect of challenging hydrological conditions, and the unpredictability of large loads, from both a forecasting and operational perspective. Multiple assessment areas have revised load forecasts downward from mid-2025 projections to account for the observed rate of completion for large load interconnections and the slower-than-expected pace at which some of those loads are coming on-line. Still, aggregated peak demand across all assessment areas has increased by over 11 GW from Summer 2025 projections that were set earlier in 2025. That level of growth exceeds the year-on-year rise of 10 GW that preceded Summer 2025. As important as the demand growth itself is the timing of the demand. The early arrival of summer heat and high demand in March has highlighted the risks associated with potential overlaps between spring maintenance outages and high demand. The importance of shoulder season supply-demand analysis continues to grow. The BPS has added slightly more than 58 GW of new resources year on year heading into the coming summer. This large resource addition has partly contributed to the improved risk outlook for some areas. The resource additions continue to include a high proportion of variable energy resources, supporting the prioritization of low-wind event preparation and probabilistic analysis of available energy at peak and risk hours.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2026.

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments webpage.

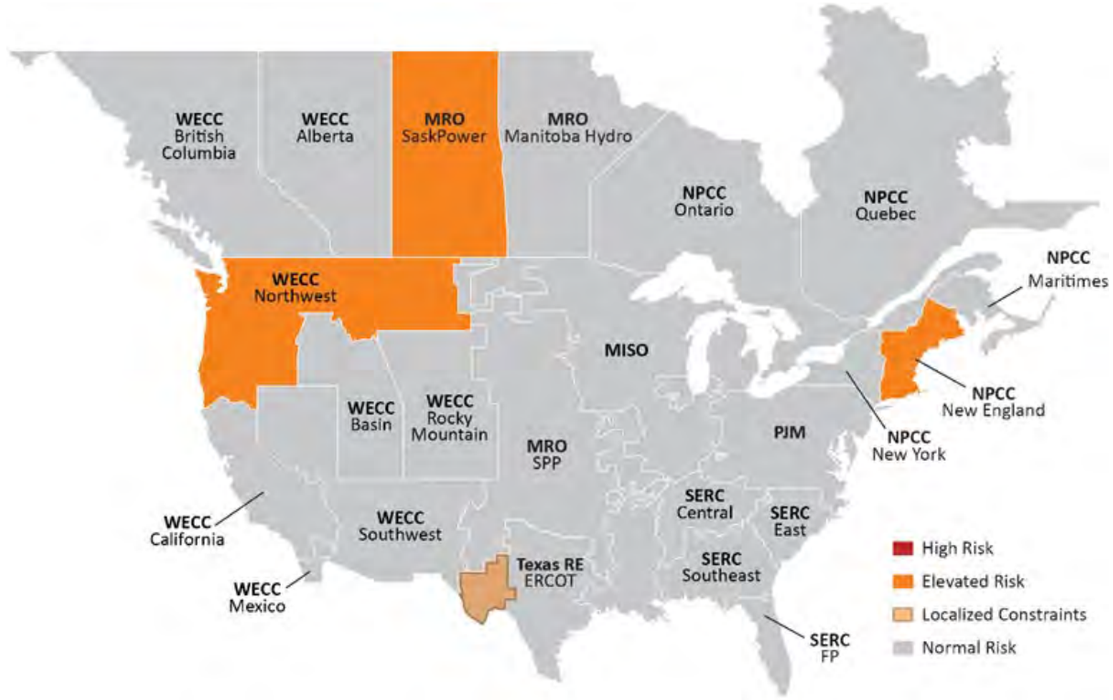
Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face elevated risks of electricity supply shortfalls during periods of more extreme summer conditions or are subject to localized constraints that raise the risk levels of certain small areas within the broader system. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar photovoltaic (PV) energy conditions:

- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2026 Summer peak demand forecast for normal conditions with an Anticipated Reserve Margin of 14%, just above the Reference Margin Level of 13%. New England may rely on non-firm imports to cover shortfalls even as the region has lowered its projected net firm imports by 836 MW from the previous year's projections to just 409 MW for the coming summer season. The decline in firm transfers is the main driver of the 2.6% year-on-year drop in anticipated resources. Non-firm imports, however, received a boost in January with the addition of New England Clean Energy Connect (NECEC), a symmetric monopole +/- 320 HVdc line from the Appalaches substation in Québec to a new substation in Lewiston, Maine. NECEC will be used as an "import-only" tie with Hydro Québec and can import up to 1,200 MW into New England. Total internal demand for the 50/50 peak summer demand forecast is 25,228 MW, up marginally from the demand projections in the *2025 SRA* of 25,202 MW. Expected increases in electrification are the biggest driver in the region's demand forecast as well as slight weather normalization changes. Other resource types have slightly increased from last year within the region. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2026 for the base case (50/50 normal demand). For the scenario with the highest peak load and reduced resources, the results were a cumulative loss of load expectation (LOLE) of <0.35 days/period, loss of load hours (LOLH) of <1.2 hours and expected unserved energy (EUE) of 628 MWh/period.
- **MRO-SaskPower:** SaskPower was at elevated risk in the *2025 SRA*, and resource adequacy metrics have declined slightly year on year for the upcoming summer period. Reserves have tightened from 34% to 29% due to a ~1.9% demand growth and no substantial change in resources. While SaskPower does not anticipate capacity constraints or reliability issues under normal conditions, extreme summer conditions may cause SaskPower to require maintenance rescheduling, short-term power transfers from neighboring utilities, and/or available demand-response programs. SaskPower's probabilistic in-house model showed an LOLH for an elevated risk scenario for the 2026 Summer season to be 0.09 hours; the month with the highest LOLH is September (0.05 hours).
- **WECC-Northwest:** The coming summer brings challenging hydrological conditions for regions in which hydropower makes up half or more of the supply fleet. Almost the entire Western Interconnection is in the grips of a persistent drought or in an area where drought development has a greater likelihood through the end of July. In Washington, for example, the snow water equivalent was at 52% of normal levels as of April 1 this year,[2] when snowpack typically reaches its peak. While the total water year supply is forecast to be nearly average in the Columbia River Basin, snowpack peaked at low elevation and melted early in the year. This has implications for the expected resources available to the Northwest, the generation mix for which is 55% hydropower. The region is contending with a nearly 5% increase in net internal demand from the *2025 SRA* and a nearly 2% drop in existing resources as well as a roughly 43% drop in expected Tier 1 resources. Though higher modeled net transfers are projected to contribute double what they were projected to last year (albeit with the increase largely attributable to a modeling change that accounts for economic transfers), this was not enough to prevent the drop in the Anticipated Reserve Margin from 32% last year to 27% this year. For this summer's assessment, WECC's study for the Northwest region resulted in small amounts of EUE, increasing from zero in the previous probabilistic assessment. The study also indicated an LOLH of >0.1 hours/period. The hour of greatest risk occurs around 6:00 p.m. in early September.
- **Texas RE:** The Texas Interconnection is widely at a normal risk level for Summer 2026 due to a 12% jump in anticipated resources for the summer period and a 4.5% decline in projected net internal demand. The lower demand forecast is the result of updated load modeling that reflects the observed behavior of load during peak periods and more demand response from large computational loads. The results of ERCOT's Probabilistic Reserve Risk Model (PRRM) simulation indicate a low risk of declaring an energy emergency alert (EEA) during the risk hour (9:00 p.m. local time). However, the PRRM does not capture the pre-contingency load shedding risk in the Far West region of ERCOT's footprint resulting from rapid growth in both load and resources in this zone. Operational

[2] WSOR-WA

challenges could arise in Far West Texas during periods of high demand combined with low wind output and absence of solar generation. Under these conditions, transmission constraints in the Far West Texas zone may become binding. Price-responsive demand is expected to help reduce transmission congestion and maintain balance with supply during tight conditions. In addition, ERCOT and transmission service providers have developed mitigation measures to address these constraints by incorporating dynamic line ratings that account for solar irradiance along with ambient temperatures. Operating procedures that include involuntary load curtailment are in place to maintain system operating limits when needed. In September 2025, two new thermal cascading Interconnection reliability operating limits (IROL) became effective in the Far West region of ERCOT's footprint.



Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

Figure 1: Summer Reliability Risk Area Summary

Other Key Reliability Highlights

- **Weather services are expecting an El Niño weather pattern to influence the weather outlook for the 2026 Summer period.**[3] El Niño weather patterns can suppress Atlantic hurricanes, which are a major reliability consideration for the Gulf Coast and Southeast United States. Temperature and precipitation forecasts for the coming summer show a higher likelihood of hotter-than-normal temperatures in the U.S. South and West and cooler-than-normal temperatures in the upper Midwest and parts of the Northeast (see **Figure 2**). Wetter-than-normal conditions could alleviate drought severity in the Gulf Coast, but the U.S. Northwest is still expected to see drier-than-normal conditions,[4] starting with sub-average snowpack[5] heading into spring that can impact the availability of hydropower units in a region that relies heavily on hydro-fueled electricity generation. In Canada, higher-than-normal temperatures are expected across the country, with the greatest likelihood residing in northeast and southwest Canada. Snowpack in Canada is generally in average conditions. British Columbia has experienced below-average snowpack in the southwest part of the province and above-average snowpack in the Columbia and Peace regions. The **Review of 2025 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2025 SRA* and summarizes 2025 resource adequacy events.

- **A large influx of BPS resources over the past year has outpaced demand and is boosting reserves.** BPS resources for the upcoming summer have jumped by over 58.5 GW with the addition of substantial amounts of solar PV and battery resources and some new natural-gas-fired generators. Sixteen of the 23 assessment areas have increased available capacity ahead of summer. Solar PV is the leading type of new resource (+30.5 GW nameplate additions, contributing an additional 16.4 GW of capacity at peak demand). The addition of solar and batteries, which perform well under more hours of the day during summer than they do in winter, is helping to meet escalating demand and increase reserves in many assessment areas.

- **Strong load growth continues in nearly all assessment areas.** Load growth from data centers and large loads continues to propel North American electricity demand forecasts higher, with an increase in peak demand since Summer 2025 exceeding the change observed from the prior summer. Aggregated peak demand across all assessment areas has increased by over 11 GW since 2025. The level of growth exceeds the year-on-year rise of 10 GW that preceded Summer 2025. The largest increases are in parts of the U.S. West. WECC-Southwest saw the largest year-on-year increase in net internal demand at +9.5%, followed by WECC-Northwest with +4.6% and WECC-Basin with 3.8%. Overall, 19 out 23 assessment areas saw demand increases from the *2025 SRA* projections.

- **Large computational and other large loads pose operational challenges for the upcoming summer.** Recent events of unexpected disconnections underscore the need for operational readiness for the upcoming summer. For example, the Eastern and ERCOT Interconnections have observed load-reduction events with each Interconnection experiencing approximately 1,500 MW of voltage-sensitive load reduction.[6] The event in the Eastern Interconnection was primarily attributed to data centers and other power electronic loads (PEL) transferring load to backup generation, which caused frequency overshoot and high voltages. The ERCOT Interconnection event involved many different types of loads of varying sizes reducing consumption during an extended low-voltage period in West Texas due to a protection system misoperation. These load-reduction events highlight some of the potential risks posed by large loads utilizing the BPS and why NERC is closely examining this issue. NERC issued a Level 3 essential actions alert related to large loads[7] as well as a reliability guideline regarding risk mitigation for emerging large loads.[8]

- **Battery resource additions help maintain stable frequency on the grid.** Since last summer, over 16 GW of nameplate battery storage capacity has been added to the grid. Texas and the Western Interconnection continue to have the strongest growth in these resources. The *2025 State of Reliability* report noted an upward trend in frequency response capability that can be attributed to the addition of battery storage resources.[9] Charged battery storage resources can respond quickly to the abrupt decline in system frequency that occurs during disturbances and sudden imbalances, helping to maintain the nominal 60 Hz system frequency and prevent equipment damage and system instability. NERC's *2026 State of Reliability* report, to be published in June, will report on this continuing trend of improved grid frequency response.

[3] Climate Prediction Center: ENSO Diagnostic Discussion
[4] Climate Prediction Center: Seasonal Drought Outlook
[5] WSOR-WA
[6] *Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions*, NERC, January 2025. Available: https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf
[7] NERC Level 3 Alert: Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control
[8] Risk Mitigation for Emerging Large Loads
[9] NERC State of Reliability reports

- **The overlap of early summer heat and spring maintenance outages can lower operating reserves in the shoulder season and early summer.** March 2026 was the warmest March in the 132 years of recordkeeping in the contiguous United States.[10] The average temperature across the country was 9.4°F above the 20th-century average. Raising the average were at least 10 states in the U.S. West that had their warmest March on record. The widespread heat-dome bled across the border and infused unseasonably warm temperatures into British Columbia as well, with at least five communities in the southern part of the province recording their warmest overnight low temperatures ever observed for the month of March.[11] Some assessment areas in the West have reported that extended lead times for hydro unit overhauls and the limited availability of engineering, procurement, and construction contractors are contributing to longer outage durations that complicate maintenance planning. Longer-than anticipated maintenance periods, in turn, can lead to higher-than-expected calls on electricity imports from neighboring regions. In other areas, there are older sites that may require extensive overhauls, such as generator rewinds that can keep resources out of service for extended periods of time, potentially longer than planned, as discovery work manifests into additional maintenance.
- **Impacts of wind drought (i.e., low wind periods) pose a risk to reliability.** Areas of the North American electric grid continue to experience periods of wind drought or steep wind down-ramping, and installed wind capacity across the BPS is up by 3% year on year. It is critical that areas experiencing these events continue to maintain operational awareness, including accurate forecasts and appropriate operating procedures to mitigate these periods. Additionally, the impact of wind ramp events—particularly down ramp—must be anticipated and planned for such that appropriate resources are ready to replace the energy lost during these conditions. It is not uncommon for areas to experience several thousands of megawatts of wind energy coming off-line during these events. For example, in January 2025, MISO experienced a wind reduction event of 1,600 MW per hour, which also coincided with a solar ramping down and evening load ramp up.[12]

[10] Assessing the U.S. Temperature and Precipitation Analysis in March 2026 | News | National Centers for Environmental Information (NCEI)
[11] Blazing hot: 1,000+ records fall in brutal March heat wave - The Weather Network
[12] *Incident Review: Preparing the Grid for Wind Energy Droughts and Down-Ramps*, https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_low_wind_event.pdf

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- Reliability Coordinators (RC), Balancing Authorities (BA), and Transmission Operators (TOP) in the elevated-risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of above-normal demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. Past system performance reviews noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[13]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- RCs, TOPs, and BAs should review outage coordination processes and policies and consider if adjustments are needed to account for potential above-normal temperatures to extend beyond the traditional summer season. Those same entities should also be prepared to adjust operating plans in early summer for delayed return-to-service of BPS generation and transmission elements.
- BAs should consider the following steps to reduce risks to system balance from conditions that could affect resources or demand for the upcoming summer:
  - **Wind energy:** In areas with ample wind resources, employ proactive operating plans for low-wind events and wind down-ramping events when weather conditions are developing or are uncertain.
  - **Hydro availability and output:** In areas with a predominance of hydro generation in the supply stack, consider in operating plans the potential for low water conditions to affect hydro generation. Coordinate a sufficient supply of alternative resource types and ready necessary demand-side management mechanisms if needed.
  - **Large computational load disconnects:** Be aware of the potential for load reductions from large computational loads in response to system conditions and include conservative practices in operating plans. Refer to NERC's incident reviews for details of recent events involving voltage-sensitive data centers and cryptocurrency mining facilities.[14]

[13] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.

[14] See Incident Review section of NERC Event Analysis page.

Risk Highlights

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. March of this year brought record heat for the month and exacerbated concerns over persisting or worsening drought, concerns that gained even more traction following an underwhelming snowpack peak in the Pacific Northwest in April. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

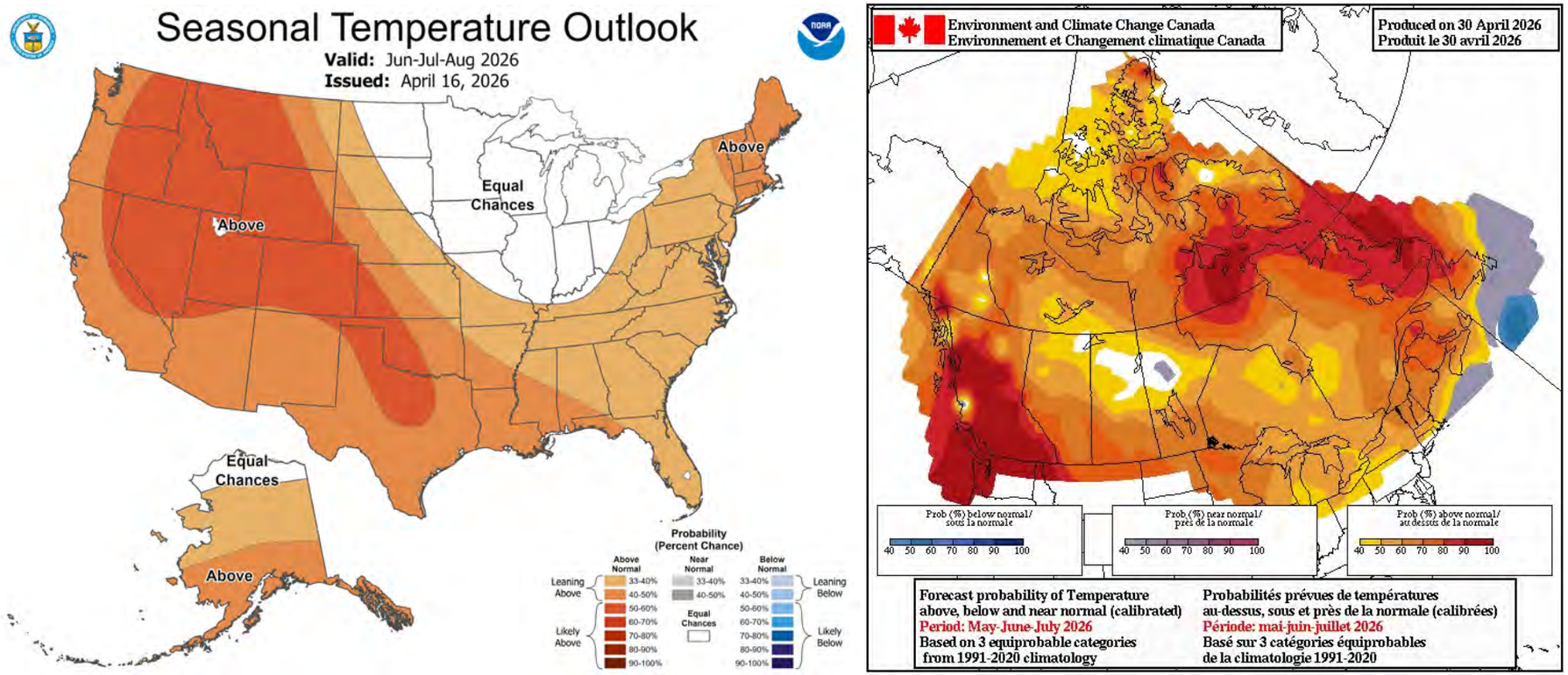


Figure 2: United States and Canada Summer Temperature Outlook[15]

[15] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Demand and Resource Trends

Strong load growth from data centers and large loads continues to propel North American electricity demand forecasts higher, with an increase in peak demand since Summer 2025 exceeding the change observed from the prior summer. Resource additions over the past year have outpaced demand growth, contributing to higher reserves.

Summer Electricity Demand Continues to Rise

Aggregated peak demand across all assessment areas has increased by over 11 GW since 2025, comparing forecasted net internal demand (NID). This measure of peak demand is inclusive of the benefits from demand response, which offset total internal demand (TID) (see **Figure 3**). NID continues to accelerate. The year-on-year increase in peak demand for Summer 2025 was 10 GW—more than double the increase in peak demand from 2023 to 2024.

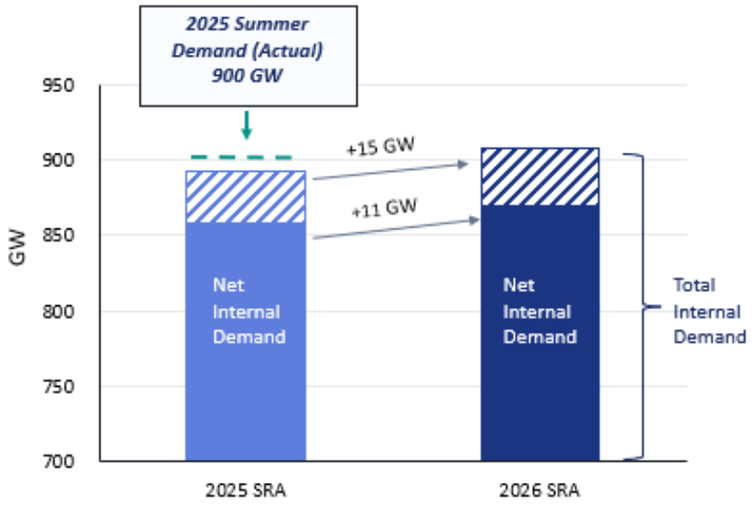


Figure 3: BPS Total and Net Internal Demand
Aggregated Peak Demand from All Assessment Areas

Nearly all assessment areas are experiencing demand growth. Peak demand forecasts have risen since 2025 in 19 of the 23 assessment areas. The largest increases are in parts of the U.S. West. In Canada, all provinces are forecasted to have increases of 2% or more except for Québec, which is forecasting a 1% decline in peak demand. Texas RE-ERCOT is a notable exception to the growth trend this summer. TID in ERCOT declined by 1.9 GW (2.3%), largely driven by updated forecasting that accounts for observed behavior of large computational loads at peak demand. NID, which includes demand response, is 3.7 GW lower (4.6%) compared to last summer because more data centers can be curtailed by grid operators when needed to prevent grid emergencies. A summary of assessment area demand changes is provided in the **Net Internal Demand** section.

More Resources Available for Summer

BPS resources for the upcoming summer have jumped by over 58.5 GW with the addition of substantial amounts of solar PV and battery resources and some new natural gas-fired generators (see **Figure 4**). Sixteen of the 23 assessment areas have increased available capacity ahead of summer. Solar PV is the leading type of new resource (+30.5 GW nameplate additions, contributing an additional 16.4 GW of capacity at peak demand). Battery additions account for 14.7 GW in increased on-peak capacity. These resources also help balance variability in solar PV and wind resources, as well as demand fluctuations. Other capacity changes since 2025 amounting to 19 GW are attributed to resource additions of other types as well as changes to generator availability (e.g., completion of extended nuclear generator outages, changes to maintenance plans). The addition of solar and batteries, which perform well under more hours of the day during summer than they do in winter, is helping to meet escalating demand and increase reserves in many assessment areas.

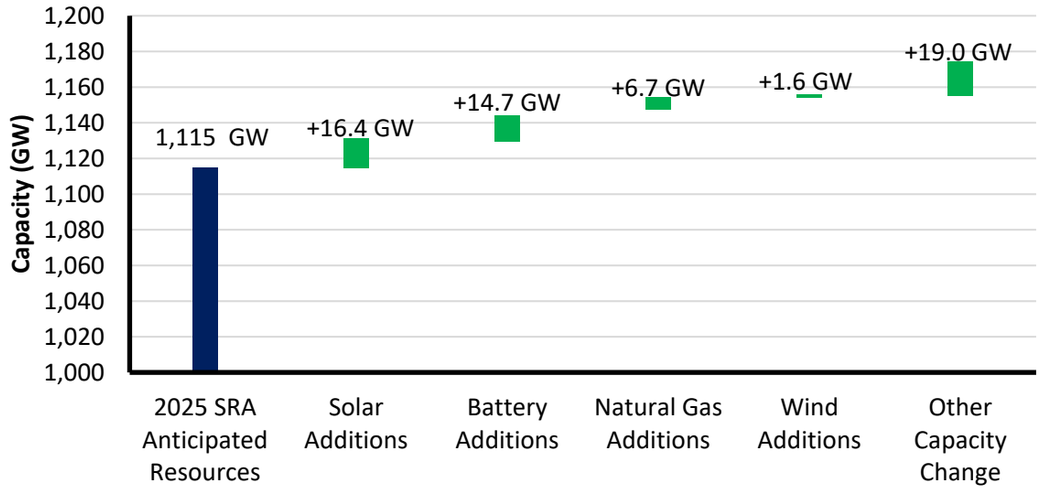


Figure 4: Summer BPS Resource Capacity Change Since 2025

Generators Extended by Federal Power Act Emergency Authority

Starting in 2025, the Department of Energy (DOE) issued emergency orders, pursuant to section 202(c) of the Federal Power Act, requiring that six different power plants maintain operational availability. Thermal generators with diverse fuel sources can be an important electricity resource, especially during winter when solar PV and battery resources are less capable compared to summer months. The DOE has since renewed those emergency orders, extending availability requirements into late May and early June (see **Table 1**). These plants and units were not incorporated into the anticipated resources of their corresponding assessment areas for Summer 2026 but may be called upon within the orders' time frames.

Table 1: Power Plants Impacted by Department of Energy 202(c) Orders in 2025 and 2026

Assessment Area	Plant Name	Nameplate Capacity (MW)	Summer Capacity (MW)	DOE 202(c) Order Expiration
MISO	J.H. Campbell	782	760	5/18/2026
MISO	F.B. Culley Generating Station	104	90	6/21/2026
MISO	Schahfer Generating Station	847	722	6/21/2026
PJM	Eddystone Generating Station	782	760	5/24/2026
WECC-NW	Centralia Generating Station	730	670	6/14/2026
WECC-RM	Craig Station	446	427	6/28/2026

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in **Table 2**.

Table 2: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2 hours or higher across the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand with **normal resource scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours across the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under extreme peak-day demand with **normal resource scenarios**[2] (i.e., typical or expected outage and derate scenarios for conditions) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand with **reduced resource scenarios**[3] (i.e., extreme outage and derate scenarios)
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible (e.g., LOLH below 0.1 hours across the season) • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1] The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2] **Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the peak demand.
[3] **Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4] Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in **Table 3**.

Table 3: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	31.1%	21.6%	3.8%
MRO-Manitoba	13.2%	9.5%	4.3%
MRO-SaskPower	29.2%	23.2%	7.3%
MRO-SPP	26.8%	21.4%	3.8%
NPCC-Maritimes	83.8%	73.4%	53.3%
NPCC-New England	14.0%	4.0%	-0.9%
NPCC-New York	34.2%	15.0%	7.5%
NPCC-Ontario	32.4%	32.4%	12.3%
NPCC-Québec	34.5%	16.4%	7.3%
PJM	26.2%	16.1%	3.8%
SERC-C	18.9%	13.9%	5.6%
SERC-E	26.3%	17.4%	10.3%
SERC-FP	25.8%	20.7%	13.6%
SERC-SE	36.9%	33.1%	24.7%
TRE-ERCOT	67.9%	60.2%	20.4%
WECC-AB	32.3%	28.2%	9.1%
WECC-Basin	37.6%	34.9%	11.5%
WECC-BC	40.5%	40.0%	9.6%
WECC-Cal	55.6%	54.3%	17.0%
WECC-Mex	32.5%	25.5%	11.0%
WECC-NW	26.9%	25.2%	8.8%
WECC-RM	51.9%	49.2%	21.5%
WECC-SW	48.1%	44.7%	25.2%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each

dashboard provide potential summer peak demand and resource condition information, as well as risk hour resource condition information for areas where the risk hour differs from the peak demand hour. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 3**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be on maintenance or forced outage during peak demand conditions. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's summer risk scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 4**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2026. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

EEA Levels

EEA Level	Description	Circumstances
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 4: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	Planning Year 2026–2027 LOLE Study Report	MISO's values for LOLH and EUE are taken from the noted assessment report, where the annual LOLE was set at 1 day in 10 years or 0.1 LOLE but equated to 0.076 LOLE for the summer. For Summer 2026, LOLH is 0.235 hrs/year and EUE is 983.8 MWH/year for the Reference Margin Level. Expectations for load loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	2024 and 2025 NERC Probabilistic Assessment (ProbA)	Manitoba Hydro's probability-based resource adequacy risk assessments for the summer season display risk when hydro flow conditions are low and load is higher than expected. Based on the analysis that was conducted for the 2024 and 2025 ProbA, this risk was considered low as normalized EUE was less than 2 parts per million and LOLH was less than 0.2 hrs/year.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2026	SaskPower conducted a probability-based capacity adequacy assessment for the 2026 Summer season. This assessment considered uncertainties in load forecasts, wind forecasts, and forced generation outages to calculate the expected number of hours with energy deficiencies (LOLH). LOLH equated to 0.09 hrs/season, and the month of highest risk has shifted from June to September, when the system experiences the largest uncertainties in load and generator availability forecasts. September risk makes up over 50% of summer season risk within this assessment area. SaskPower indicated that in extreme conditions, it may have to use short-term power transfers from neighboring utilities, maintenance rescheduling, and/or demand-response programs to prevent energy shortfall.
MRO-SPP	SPP East Assessment Area and 2024 NERC Probabilistic Assessment (ProbA)	Based on SPP East's probabilistic assessment and the 2024 NERC ProbA, risk observed in summer 2026 was minimal. Risk hours that materialized during simulations occurred during late afternoon and early evening periods and were driven by high demand and low wind conditions.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		The preliminary results of NPCC's probabilistic assessment indicate that the Maritimes Area is not expected to require use of its established operating procedures designed to mitigate resource shortages during Summer 2026 based on a probabilistic-based assessment. The Maritimes Area did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks, and established operating procedures were sufficient to maintain a balance over the May–September summer period for all the scenarios modeled.
NPCC-New England		The preliminary results[16] of NPCC's probabilistic assessment indicate that use of New England's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages. Preliminary cumulative LOLE (days/season), LOLH (hours/season), and EUE (MWh/season) risks were reported as negligible over the summer May to September period for the expected load with expected resources scenario. Under an extreme scenario, the estimated cumulative LOLE risk is 0.343 days/period, with associated LOLH of1.178 hours/period and EUE of 628 MWh/period with the highest risk occurring in June, with some in July and August.

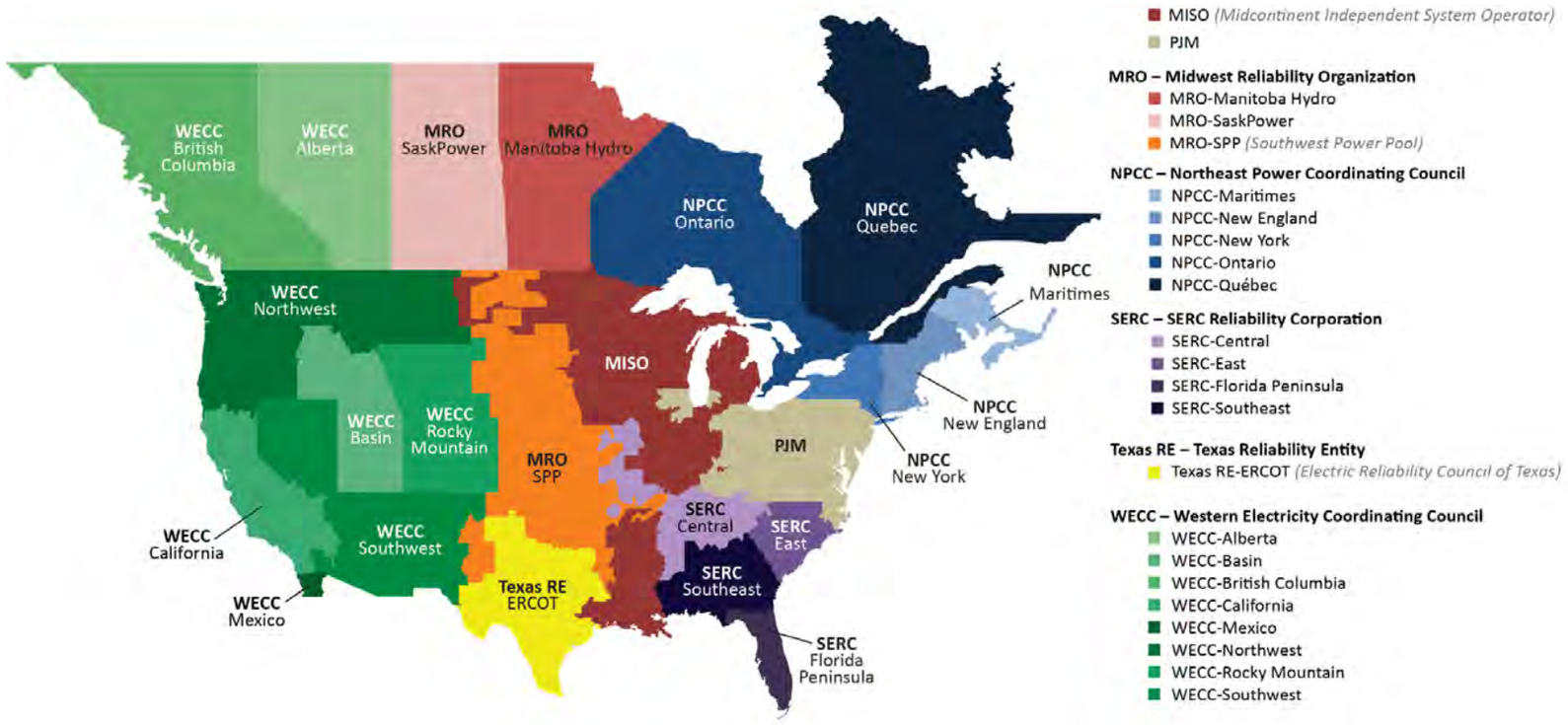
[16] Based on preliminary runs from March 31, 2026

Table 4: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-New York		The preliminary results of NPCC's probabilistic assessment indicate that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026 with less than 0.017 days of LOLE, 0.042 hours of LOLH, and 20 MWh of EUE, which is below elevated risk criteria under the scenario of highest peak load and reduced resource conditions; the estimated cumulative risk reached 0.655 days of LOLE, 2.004 hours of LOLH, and 1,262 MWh of EUE, with the greatest risks occurring in July and August.
NPCC-Ontario		The preliminary results of NPCC's probabilistic assessment indicate that operating procedures are not needed to maintain a balance between electricity supply and demand. Even under peak load and low-resource conditions, the risk of LOLE remained negligible. This stability is supported by nearly 1,100 MW of new capacity from recent gas facility upgrades and storage projects. Consequently, no emergency operating procedures were required to maintain the balance between supply and demand.
NPCC-Québec		The preliminary results of NPCC's probabilistic assessment indicate that Québec area is not expected to require use of its operating procedures designed to mitigate resource shortages during Summer 2026 based on a probabilistic-based assessment. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking. The Québec area expects to be able to help other areas if needed.
PJM	2023 PJM Reserve Requirement Study (RRS)	The RRS analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer. PJM is forecasting 26% installed reserves (including expected committed demand response), which is above the reserve requirement margin of 18.6% necessary to meet the 1-day-in-10-years LOLE criterion.
SERC	Probabilistic resource adequacy assessment for the 2026 Summer season	SERC performed a probabilistic resource adequacy assessment for the summer season (June–September) using the PowerGEM SERVM model. The analysis is based on an 8,760 hourly model with 5,375 Monte Carlo simulations per hour and incorporates data across 43 historical weather years (1980–2022), load forecast uncertainty, generator forced outages, power transfer between SERC assessment areas, and variable energy resource performance.
SERC-Central		Results from the summer 2026 probabilistic risk assessment indicate that resources will be sufficient to meet projected demand and do not exhibit any EUE or LOLH.
SERC-East		Simulations performed show that small amounts of EUE materialized in a single summer evening hour under a high-stress scenario involving elevated load, reduced solar output during the evening ramp, and coincident generator outages. The magnitude and frequency of the event are low and do not indicate a broader resource adequacy concern.
SERC-Florida Peninsula		No EUE or LOLH materialized within SERC-Florida Peninsula across all simulations, which resulted in an implied LOLE of approximately zero. These results indicate that available resources are sufficient to meet projected demand under modeled conditions.
SERC-Southeast		The probabilistic assessment did not identify any loss of load events for SERC-Southeast during the Summer 2026 season. EUE and LOLH were both zero across all simulation hours.
Texas RE-ERCOT	ERCOT probabilistic assessment using the PRRM	The simulation indicates low risk of having to declare an EEA for hour 21, the highest risk hour for the peak load day in August (which is also the expected summer peak load day) with a probability of declaring an EEA of 0.43%. This is categorized by ERCOT as "low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2025 SRA*, ERCOT reported EEA declaration probability for hour ending 21 of 3.1%. The large decrease in EEA probabilities is due to the addition of 8,780 MW of BESS capacity in 2025 and 2,677 MW more as of March 2026.

Table 4: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC	Probabilistic resource adequacy assessment for the 2026 Summer season	For the 2026 SRA, WECC, for the first time, performed a probabilistic resource adequacy assessment using the PowerGEM SERVM model based on an 8,760 hourly model that incorporates data across 43 historical weather years, load forecast uncertainty, generator forced outages, power transfers, and variable energy resources shapes. With this shift, WECC opted to default to the NERC defined Reference Margin Level and change its reporting to reflect the different data construct and reporting of results.
WECC-AB		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC–Basin		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-BC		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-CA		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-Mex		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-RM		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-NW		WECC's probabilistic analysis showed EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions.
WECC-SW		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables** section), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables** section) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the SRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.





MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

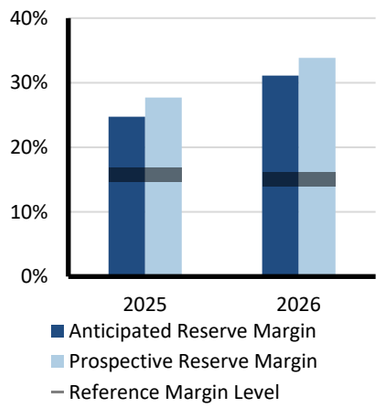
Highlights

- Although MISO's peak load has increased by 2.5 GW from the *2025 SRA*, MISO is not anticipating operational or reliability issues for the 2026 Summer season. Load growth is driven by increased projections of data center load and is expected to accelerate in 2027 and beyond, which may lead to increased reliability risk in the future if resource additions cannot keep pace with rising load forecasts.
- MISO's capacity resources have improved since Summer 2025, and new additions are made up of predominantly solar resource installations, along with smaller amounts of natural gas, wind, and battery storage resources. Solar resources are helping the system serve peak load but are shifting risk hours to later in the day where intermittent resource capabilities are low and temperatures are above expected conditions.
- MISO benefits from transmission connections with neighbors to meet extreme weather conditions, and reliance may increase when extreme conditions arise.

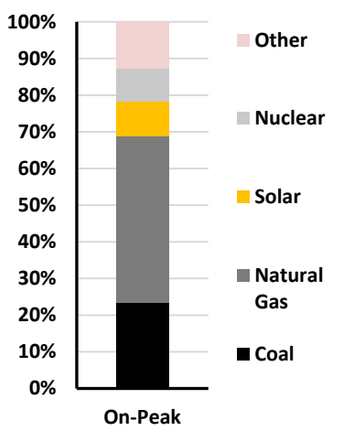
Risk Scenario Summary

Expected resources meet operating reserve requirements for assessed scenarios. Above-normal summer peak load combined with low resource conditions could result in the need to employ operating mitigations (e.g., load-modifying resources) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access demand-response resources when operating reserve shortfalls are projected.

On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand forecast (50/50) plus transmission losses.

Maintenance Outages: Rolling three-year average of maintenance outages that occurred during the summer (June-September) peak hour.

Forced Outages: Rolling three-year average of forced outages that occurred during the summer (June–September) peak hour.

Extreme Derates: Rolling three-year average of maintenance and planned outages that occurred across thermal resources during the summer (June-September) peak hour, plus a reduction in solar resource performance during the risk hour.

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme conditions.



MRO-Manitoba Hydro

Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the RC for Manitoba Hydro.

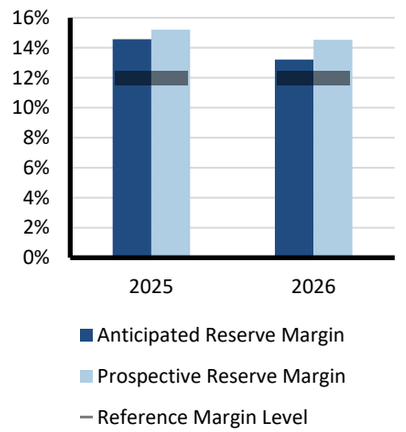
Highlights

- Manitoba Hydro is not anticipating any operational challenges or emerging reliability issues in its assessment area for Summer 2026.
- Manitoba Hydro's demand increase of 2.5% is driven primarily by population and economic growth, including electrification of a large industrial customer to reduce carbon emissions. Currently, new cryptocurrency operations cannot connect in Manitoba due to a moratorium.
- The 2024 ProbA for the 2026 load year shows an EUE of 4 MWh and an LOLH of 0.05 hours.
- Manitoba Hydro's reservoir storage conditions are below average, but winter snowfall has been above average, which should favorably impact spring runoff. The Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought. Manitoba Hydro expects to reliably supply its internal demand and export obligations, even if extreme drought develops through 2026–2027.
- Manitoba Hydro continues to monitor summer resource adequacy in the MISO area but does not believe that there are significant seasonal reliability issues in MISO or in other neighboring assessment areas that have potential to impact Manitoba Hydro operations for Summer 2026.
- The Anticipated Reserve Margin for Summer 2026 exceeds the 12% Reference Margin Level.

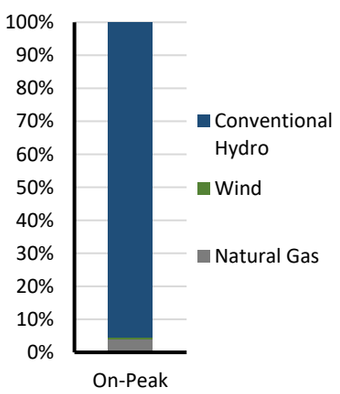
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

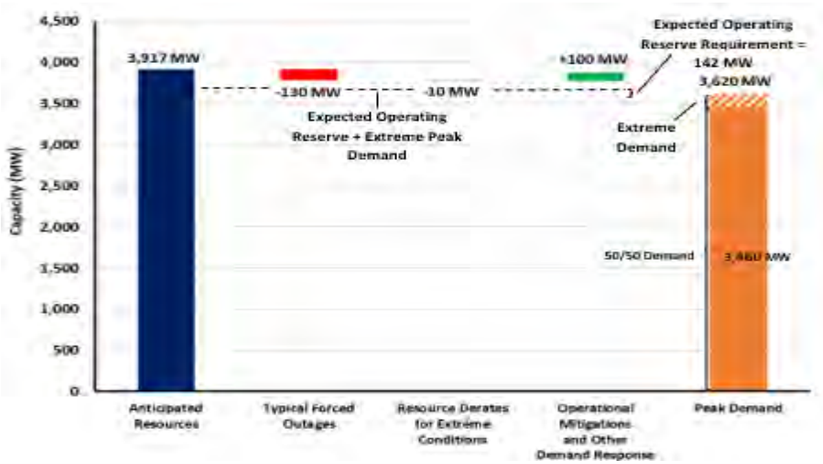
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: 50/50 Demand with allowance for extreme demand based on a 90th percentile extreme weather scenario of 36.0 C (96.8 F).

Forced Outages: Typical forced outages.

Extreme Derates: Summer wind capacity accreditation of 18.2% of nameplate rating based on MISO seasonal analysis. No further wind output derates based on experience; wind farms constitute less than 1% of Manitoba Hydro's available capacity.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; assume 100 MW of non-firm imports available.



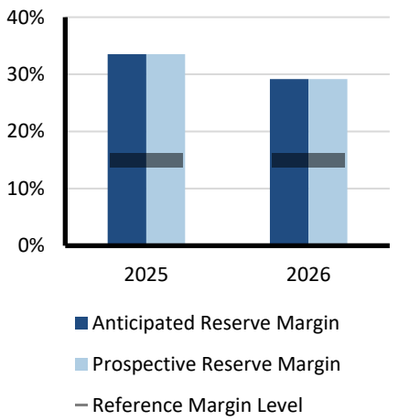
MRO-SaskPower

MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

Highlights

- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- There is a 1.9% increase in TID from the *2025 SRA* projection. This growth is mainly driven by population growth in the province, expansion projects, reduced self-generation in the industrial sector, and increased electrification.
- SaskPower conducted a probability-based capacity adequacy assessment for the 2026 Summer season. This assessment considered uncertainties in load forecasts, wind forecasts, and forced generation outages to calculate the expected number of hours with energy deficiencies (LOLH). According to probabilistic in-house model, the LOLH for an elevated risk scenario for the 2026 Summer season is 0.09 hours, which is nearly in line with the 0.1 LOLH risk criteria NERC sets for the elevated-risk level. The month with the highest LOLH is September (0.05 hours).
- Based on the planned maintenances, typical forced outages from historical data, and expected renewable generation under the normal and extreme demand conditions, SaskPower does not anticipate any reliability issues during Summer 2026. Under extreme conditions, however, SaskPower may have to use short-term power transfers from neighboring utilities, maintenance outage deferrals, and/or demand-response programs to maintain sufficient supplies.

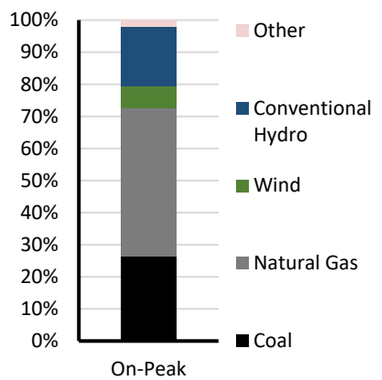
On-Peak Reserve Margin



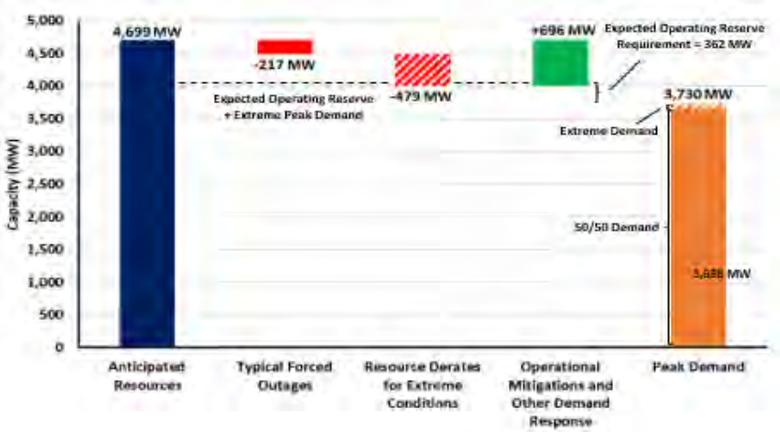
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand and outage conditions. During extreme summer conditions causing above-normal demand or generator outages, SaskPower can experience operating reserve shortfalls that it would mitigate using rescheduled planned maintenance, short-term power transfers from neighboring utilities, and/or available demand-response programs.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads.

Forced Outages: Based on historic generation stats and SaskPower's forced outage rate models.

Extreme Derates: Based on the wind turbines datasheet and the percentage of the total available wind that will be cut off when the temperature is extremely high (40 degrees and higher).

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7 days' notice. In addition, 176 MWs of demand response can be called upon during operating emergencies.



MRO-SPP

The Southwest Power Pool (SPP) PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

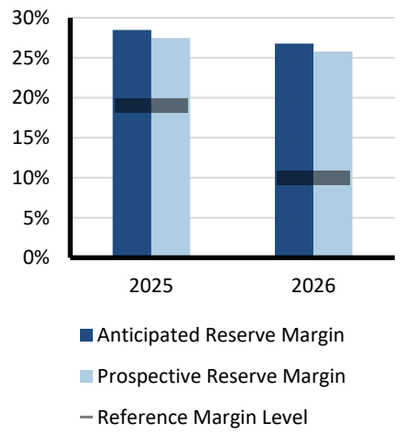
Highlights

- At this time, SPP does not anticipate any operational challenges that would result in reliability risk under normal conditions.
- SPP has operational procedures in place to manage generation outages taken over the summer to ensure appropriate generation is in place for high load. These procedures utilize probabilistic forecasts on factors such as load, generation, and outages to prepare for upcoming peak conditions.
- With heavy reliance on wind generation, SPP's greatest summer risk periods are when wind availability is low. If these low wind periods correspond to peak load conditions, then the combination presents extra risk for the area.
- SPP is projecting a 1.5% increase in forecasted 2026 Summer peak load vs. 2025 Summer peak actuals. Solar PV and energy storage continue to grow rapidly.

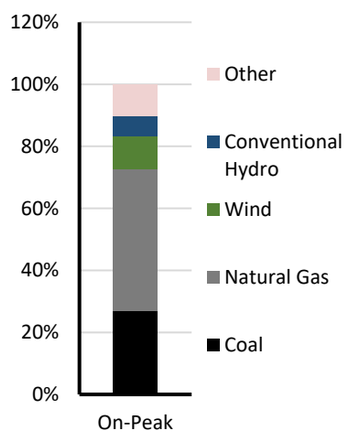
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. A combination of higher-than-average demand or lower-than-expected wind generation could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems), including resource advisories and EEAs, where appropriate.

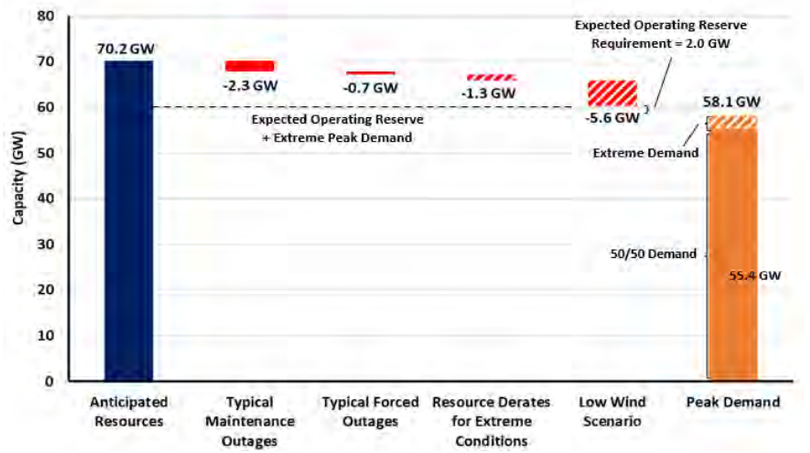
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 4.9% increase from net internal demand.

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process.

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods.

Low Wind Scenario: Derates reflecting an average low-wind day in the summer.



NPCC-Maritimes

NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. state of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the BA for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the BA for Nova Scotia. NB Power's system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

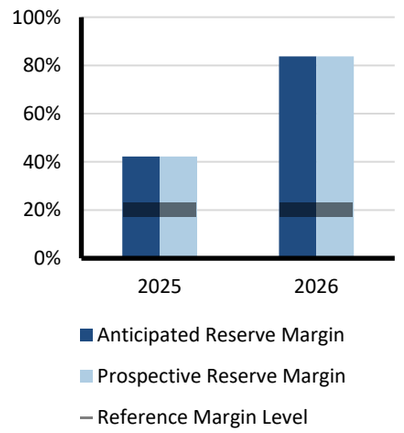
Highlights

- There are no anticipated issues for the Maritimes in the upcoming summer assessment period with sufficient firm capacity to meet the forecast peak demand.
- The Maritimes has not identified any operational issues that are expected to impact system reliability. Emergency operations and planning procedures are in place to mitigate operational events.
- Maritimes summer on-peak reserve margin is largely driven by resource maintenance outages. As a result of fewer planned outages (~1,000 MW) at peak, the 2026 on-peak reserve margin doubled from the 2025 SRA (84% compared to 42%).
- The preliminary results of NPCC's probabilistic assessment indicate that the Maritimes area is not expected use their operating procedures during the Summer of 2026 to maintain sufficient supply. The Maritimes area did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks, and established operating procedures were sufficient to maintain an energy balance over the May–September summer period for all the scenarios.
- Although margins can go negative in May under the high load (above 90:10) scenario, there are opportunities to purchase non-firm energy through the interconnections with neighboring control areas as this scenario does not coincide with either the Maritimes or the NPCC summer peaks.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to enable sustained operation in the event of natural gas supply interruptions.

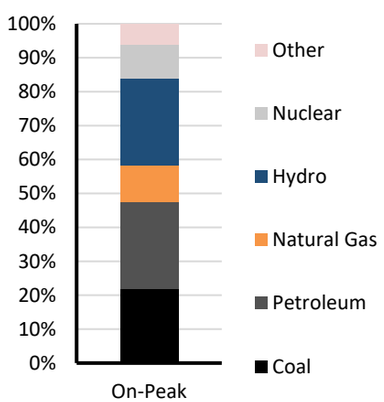
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

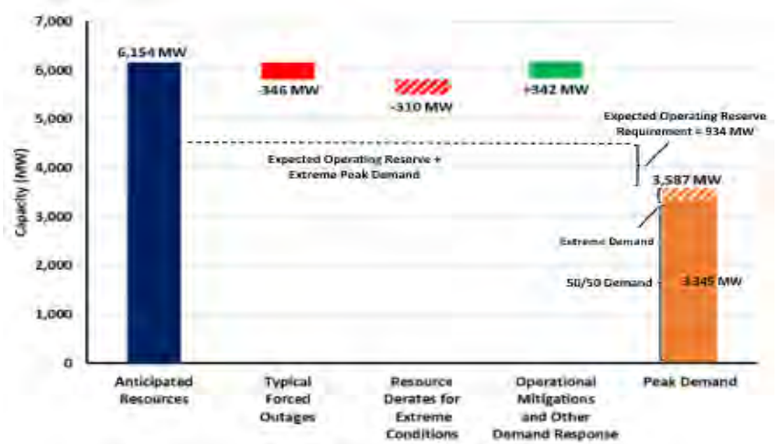
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and above 90/10 extreme demand forecast.

Forced Outages: Based on historic operating experience.

Extreme Derates: A low-likelihood scenario comprising a 100% derate of solar and storage, a 50% derate of wind (calm weather), and a 50% derate to natural gas (fuel supply issue).

Operational Mitigations: Changes to system operating conditions in the Maritimes area (i.e., transmission and/or generator outages) will be managed using short-term operating procedures (STOP), which would outline any special operating conditions for the operators.



NPCC-New England

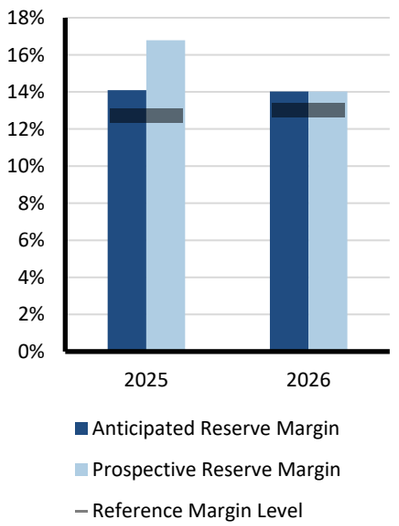
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- The New England area Anticipated Reserve Margin of 14% marginally exceeds the Reference Margin Level of 13%, avoiding a shortfall between anticipated resources and the reference level for reserves. There is, however, a 41 MW shortfall if resource additions are not included.
- ISO-NE assumes a net interchange of 409 MW, which is capacity-backed; however, ISO-NE typically imports around 3,000 MW during summer peak load conditions.
- ISO-NE does not anticipate any operational challenges or reliability issues for the upcoming 2026 Summer assessment period and forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand and operating reserves.
- Since January 2026, New England has added NECEC, a symmetric monopole +/- 320kV HVdc line from the 735 kV Appalaches substation in Québec to a new 345 kV substation, Merrill Road in Lewiston, Maine. NECEC will be used as an "import-only" tie with Hydro Québec and is capable of importing up to 1,200 MW into New England, but only on a non-firm basis for the coming summer.
- A probabilistic assessment was conducted for New England, modeling both NPCC and its neighboring regions. The analysis simulated a base case (50/50 normal demand) alongside a highest peak load scenario, which has a 7% probability of occurrence. The preliminary results of the probabilistic assessment indicate that use of New England's established operating procedures is sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026. Under the scenario of highest peak load levels and reduced resource conditions, the estimated cumulative risk reached 0.343 days of LOLE, 1.178 hours of LOLH, and 628 MWh of EUE, with the greatest risks occurring in June and July. The final NPCC 2026 Summer Reliability Assessment will be approved in May 2026.

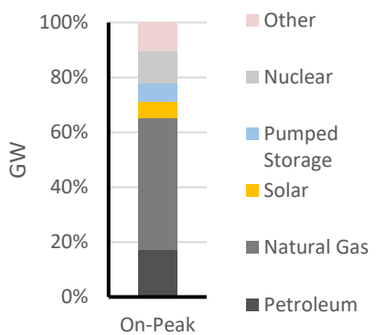
On-Peak Reserve Margin



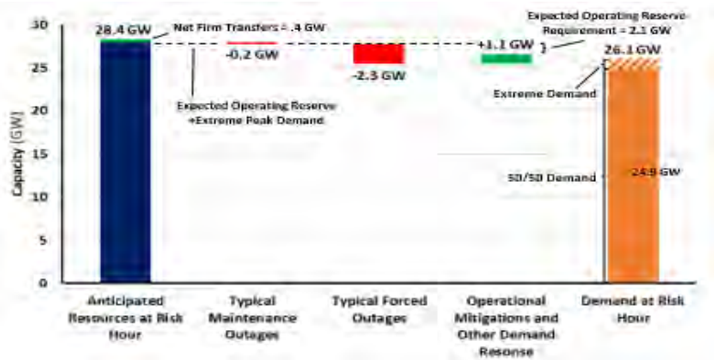
Risk Scenario Summary

The New England area expects to have sufficient resources to meet the 2026 summer peak demand forecast through the use of its established operating procedures and significant imports over its many ties to its neighbors that have historically been able to provide up to 3,000 MW during summer peak load conditions.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Forecasted risk hour demand (50/50) and (90/10) extreme demand adder.

Maintenance Outages: Historical average of maintenance outages.

Typical Forced Outages: Based on historical average of forced outages for summer period.

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures.



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this SRA, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an installed reserve margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2026–2027 IRM at 24.5%.

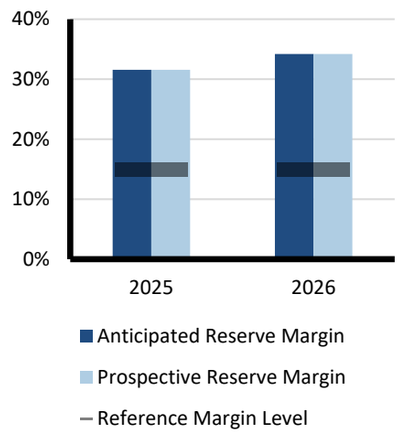
Highlights

- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer.
- Adequate capacity margins are projected for the summer peak, and prospective transactions with neighbors should mitigate reliability concerns. Operating procedures should be sufficient to handle any issues that may occur.
- The preliminary results of the NPCC probabilistic assessment indicate that use of New York's established operating procedures is sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026. The expected load and resource scenario resulted in negligible risks over the May to September summer period, with less than 0.017 days of LOLE, 0.042 hours of LOLH, and 20 MWh of EUE.
- In contrast, under the scenario of highest peak load and reduced resources, the estimated cumulative risk reached 0.655 days of LOLE, 1.996 hours of LOLH, and 1,255 MWh of EUE, with the greatest risks occurring in July and August.
- to coordinate extensively with neighboring RCs and BAs to improve situational awareness and vet needs for firm or non-firm transfers to address extreme system conditions

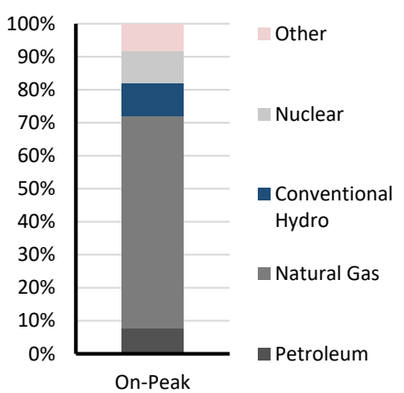
Risk Scenario Summary

The preliminary results of NPCC's probabilistic assessment indicate that New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected demand, if needed, to mitigate shortages during Summer 2026.

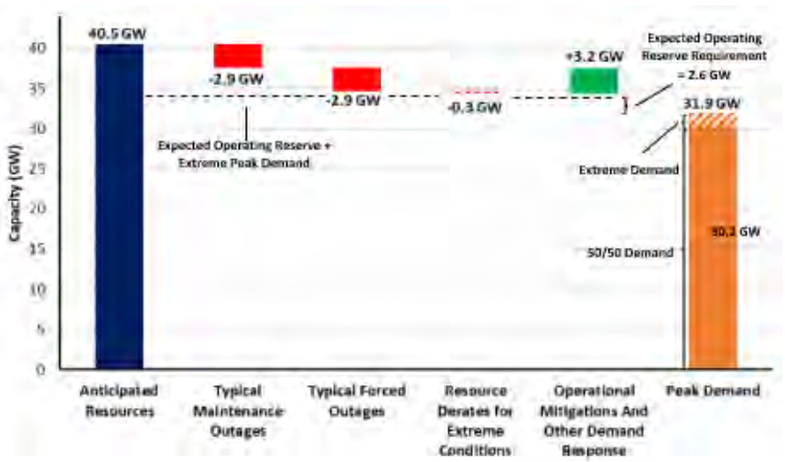
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: The risk period is at the time of peak demand.

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast. **Maintenance Outages:** Based on historical performance and the new NYISO capacity accreditation process.

Forced Outages: Based on historical five-year averages.

Extreme Derates: Estimated resources unavailable in extreme conditions.

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual.



NPCC-Ontario

NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of over 16 million people. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

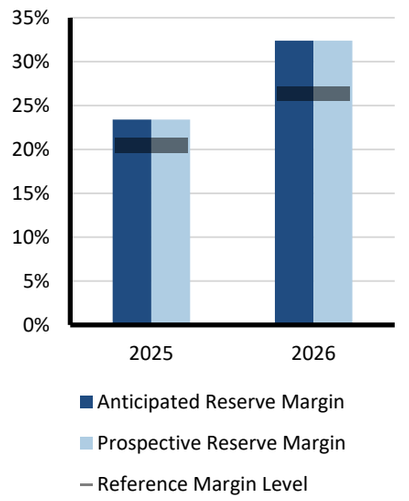
Highlights

- Ontario is well prepared for Summer 2026, and the IESO expects that the electricity system will remain reliable.
- Demand increased 2.7% over last year, driven in part by a rise in certain economic indicators, such as higher total employment, across the forecast horizon. However, uncertainty persists in the current economic environment with Ontario's largest trading partner.
- Existing-certain capacity is 8.4% higher than last year, reflecting the addition of new units. Established resource adequacy policy sets out a competitive strategy for securing new resources in the short, medium, and long terms. Also, Darlington G4 nuclear refurbishment was completed early and will be available for the summer period.
- Net firm capacity transfers increased 30.6% from Summer 2025. Although the capacity auction secured fewer imports for Summer 2026 compared to Summer 2025, IESO has chosen to utilize 300 MW of the 2015 Capacity Sharing Agreement with Hydro-Québec for the period commencing June 1, 2026, and ending September 30, 2026.
- Anticipated resources are projected 9% higher than Summer 2025 due to upgrades at existing natural gas facilities and new energy storage facilities anticipated to be coming on-line this summer.
- The preliminary results of NPCC's probabilistic assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. Even under peak load and low-resource conditions, the risk of LOLE remained negligible. This stability is supported by nearly 1,100 MW of new capacity from recent gas facility upgrades and storage projects. Consequently, no emergency operating procedures were required to maintain the balance between supply and demand.

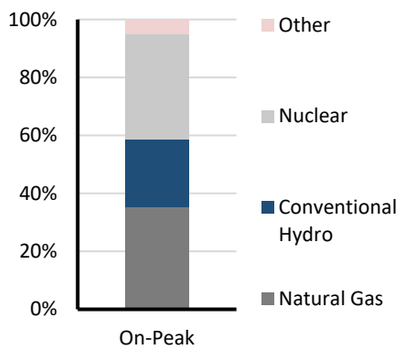
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

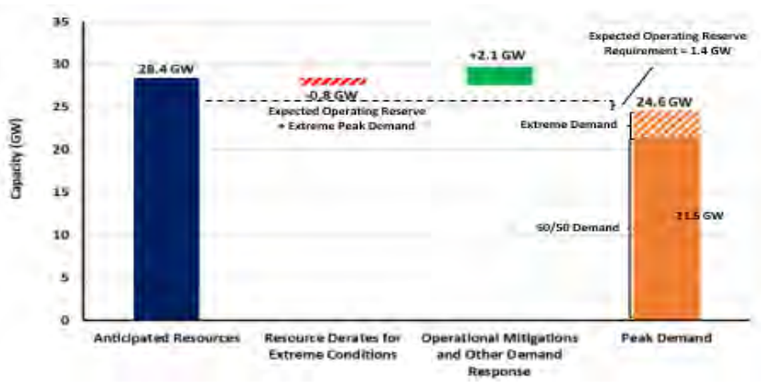
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modeled data.

Extreme Derates: Derived from weather-adjusted temperature ratings of thermal units and adjustments to expected hydro production for low water conditions.

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,100 MW for the On-Peak Risk Scenario, consisting of Imports, Public Appeals, and voltage reductions.



NPCC-Québec

NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of nearly 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominantly hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

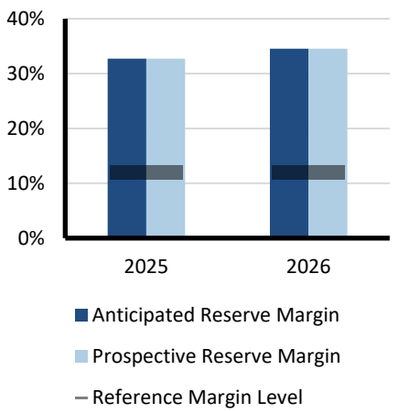
Highlights

- Québec is a winter-peaking hydroelectric system. Despite reduced generation because of reduced runoff in northern Québec since 2023, the Québec area expects no issues in meeting its operational needs this summer.
- Load (NID) is projected to decrease by 1% with respect to 2025.
- Net firm capacity exports have significantly increased (+1,018 MW) this year, as the CHPE is positioned to provide firm capacity to New York for the summer.
- There is a significant change to existing-certain capacity (3.7% or +1,192 MW). Hydro-Québec includes its planned outages in its certain capacity. This year, Hydro-Québec improved its modeling of its outages partially to account for its flexibility in managing outages; notably, the ability to recall certain outages to improve margins during peak events is highlighted.
- The preliminary results of NPCC's probabilistic assessment indicate that Québec area is not expected to require use of operating procedures designed to mitigate resource shortages during Summer 2026. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking. The Québec area expects to be able to help other areas if needed.

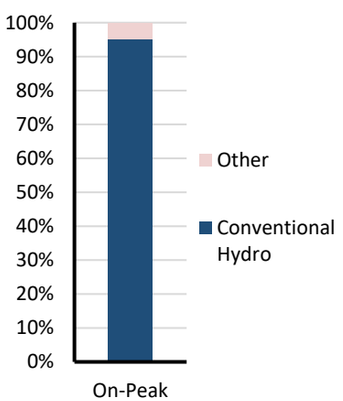
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

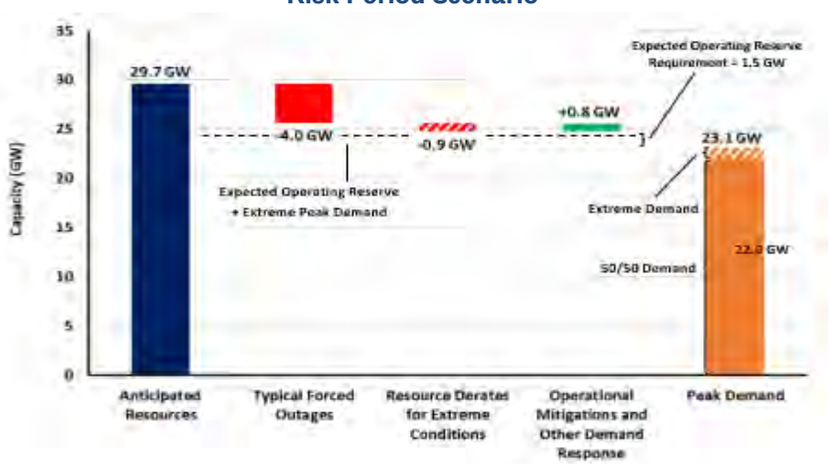
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Based on historical data and trending.

Extreme Derates: Estimated resources unavailable in extreme conditions.

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.



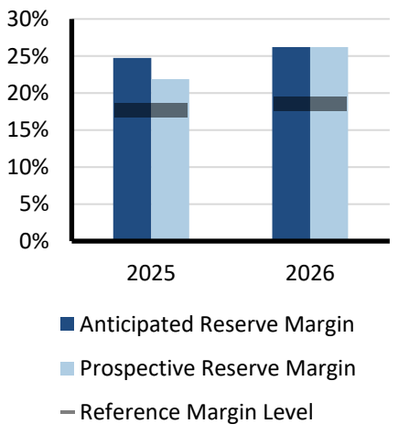
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM's footprint covers approximately 369,054 square miles and serves more than 67 million people. PJM is the area's BA, Transmission and Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

Highlights

- PJM is expecting a low risk of resources falling below the required reserve requirement during Summer 2026.
- PJM is forecasting ~26% installed reserves (including expected committed demand resources), which is above the PJM reserve requirement margin of 18.6% that is necessary to meet the 1-day-in-10-years LOLE criterion. The highest risk for unserved energy is at peak demand hour.
- If extreme high temperatures are experienced, PJM anticipates the need for demand-response resources to help reduce load.
- New and better load forecasts and advancement of planned resources have improved PJM's reserve margin looking into this summer over previous assessments.
- The LOLH and EUE values reported in the 2024 LTRA for 2026 were 0.12 hours/year and 537.52 MWh/year, respectively. These values corresponded to a 17.8% operable margin (also reported in the 2024 LTRA). Since the expected actual reserve margin for the PJM system is 26% in 2026, the LOLH and EUE values associated with a 26% reserve margin are expected to be lower than those reported in the 2024 LTRA.

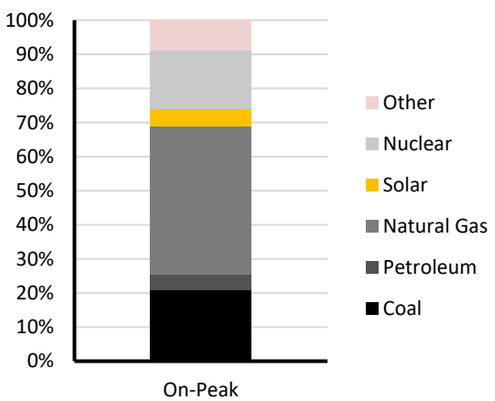
On-Peak Reserve Margin



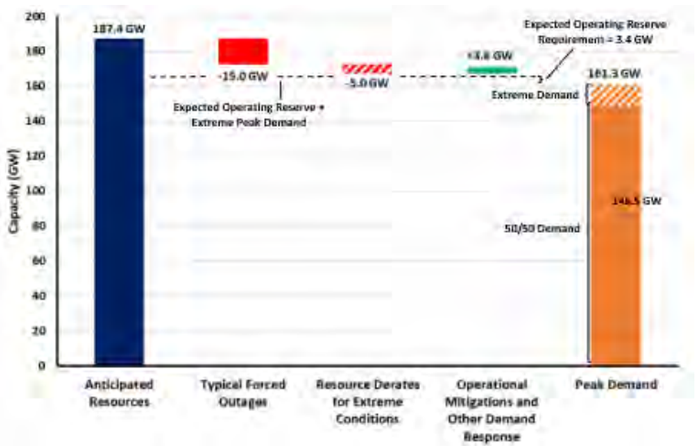
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Based on historical data and trending.

Extreme Derates: Accounts for thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: A total of 3.6 GW estimated based on operational/emergency procedures. This includes 500 MWs of additional demand response that can be called upon during operating emergencies.



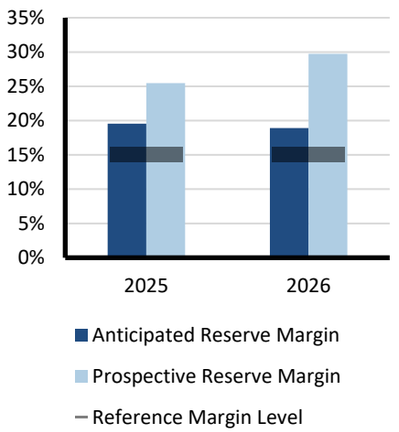
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity and includes all or portions of Alabama, Georgia, Iowa, Kentucky, Mississippi, Missouri, North Carolina, Oklahoma, Tennessee, and Virginia. SERC-Central is a dual-peaking assessment area, experiencing peak electricity demand during both the summer and winter seasons. The PCs in this subregion include Associated Electric Cooperative Inc., Louisville Gas & Electric/Kentucky Utilities, Owensboro, KY Municipal Utilities, and the Tennessee Valley Authority. Other SERC member entities in this subregion include Brookfield/Smoky Mountain, Memphis Light, Gas and Water Division, and Nashville Electric Service.

Highlights

- No significant reliability concerns were identified.
- Modest load growth (~1–3%) is driven by residential, industrial, and emerging data center demand.
- Increased demand response (DR) results from new demand-side management (DSM) programs and large industrial load enrollments.
- Adequate capacity, transfers, resource assumptions and reserve margins remain sufficient to support reliability.
- Robust operational planning and coordination, with DSM/DR programs providing additional flexibility during peak conditions.
- ProbA results show negligible risk for this summer.

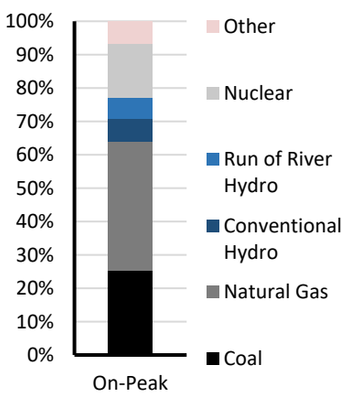
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast).

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level.

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: 1.9 GW based on operational/emergency procedures.



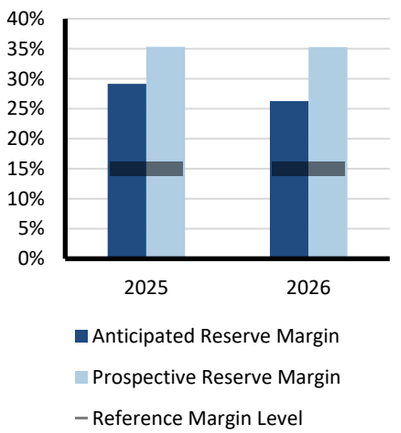
SERC-East

SERC-East is an assessment area within the SERC Regional Entity and includes North Carolina and South Carolina. SERC-East is a winter-peaking assessment area. The PCs in this subregion include Cube Hydro Carolinas LLC, Dominion Energy South Carolina Inc., Duke Energy Carolinas LLC, Duke Energy Progress LLC, and the South Carolina Public Service Authority (Santee Cooper). Other SERC member entities in this subregion include the Cube Hydro Carolinas-Yadkin Division and Southeastern Power Administration.

Highlights

- No significant operational challenges or emerging reliability issues were identified; system conditions remain adequate for Summer 2026.
- Fuel supply, generation availability, and transmission operations are expected to be adequate, with no major outages anticipated to impact reliability.
- Minimal changes are expected in demand and resource mix; reserve margins remain above planning targets despite updated solar/storage accreditation.
- Strong coordination processes and established operating procedures support reliable peak demand management.
- ProbA results show negligible risk for this summer.

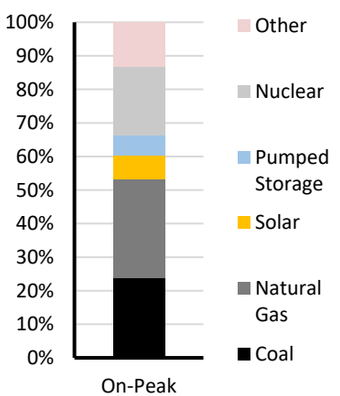
On-Peak Reserve Margin



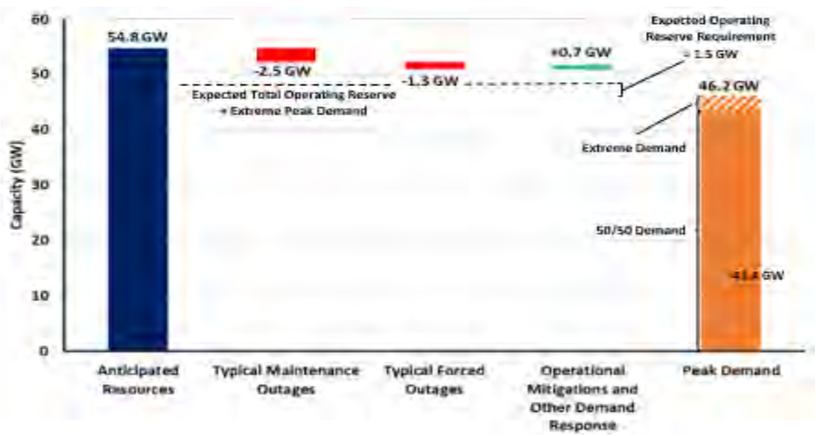
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast).

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level.

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: A total of 728 MW based on operational/emergency procedures.



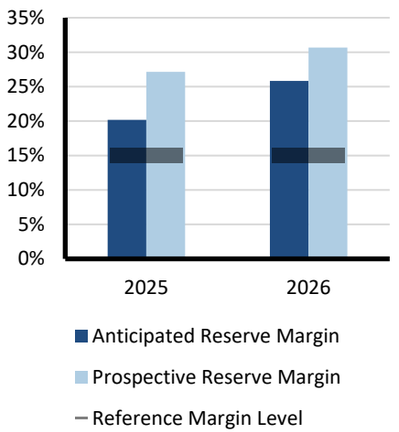
SERC-Florida Peninsula

SERC-Florida Peninsula is an assessment area within the SERC Regional Entity and includes all of Florida. SERC-Florida Peninsula is a summer-peaking assessment area. The PCs in this subregion include Duke Energy Florida LLC, the Florida Municipal Power Agency, Florida Power & Light Company, Florida Reliability Coordinating Council Inc., Gainesville Regional Utilities, the City of Homestead, JEA, Lakeland Electric, the Orlando Utilities Commission, Seminole Electric Cooperative, the City of Tallahassee, and Tampa Electric Company.

Highlights

- No significant operational challenges or emerging reliability issues were identified; system conditions remain stable for Summer 2026.
- There is an adequate demand and capacity outlook, with minimal year-over-year changes and no significant operational risks.
- There is strong resource adequacy, with projected reserve margins (~26%) well above the 15% reference margin.
- DR (~3,350 MW available) and established coordination practices support peak demand and emergency preparedness.
- ProbA results show negligible risk for this summer.

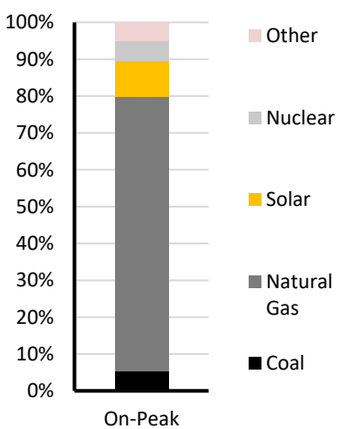
On-Peak Reserve Margin



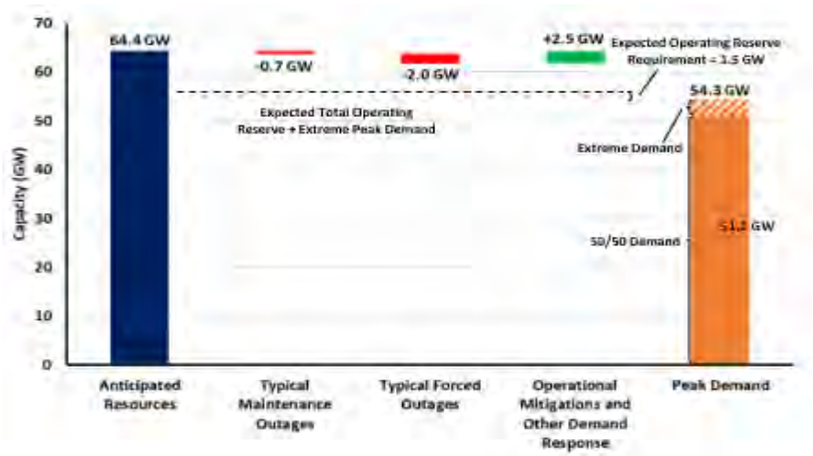
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast).

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level.

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: A total of 2.5 GW based on operational/emergency procedures.



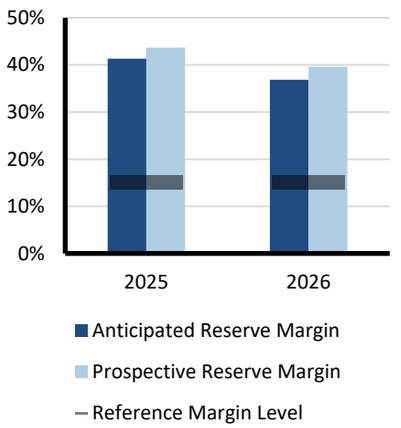
SERC-Southeast

SERC-Southeast is an assessment area within the SERC Regional Entity and includes all or portions of Alabama, Florida, Georgia, and Mississippi. SERC-Southeast is a summer-peaking assessment area. The PCs in this subregion include Georgia Transmission Corporation, the Municipal Electric Authority of Georgia, PowerSouth Energy Cooperative, and Southern Company Services, Inc. - Trans.

Highlights

- No significant reliability risks were identified; fuel supply and generation portfolios remain diverse and adequate.
- Natural gas pipeline constraints and increasing solar penetration present manageable operational considerations, not reliability threats.
- Moderate load growth (~1–3%), driven by economic conditions, residential and commercial expansion, and emerging data center load.
- Limited reliance on DR; existing operating practices and planning processes are sufficient to meet peak demand.
- ProbA results show negligible risk for this summer.

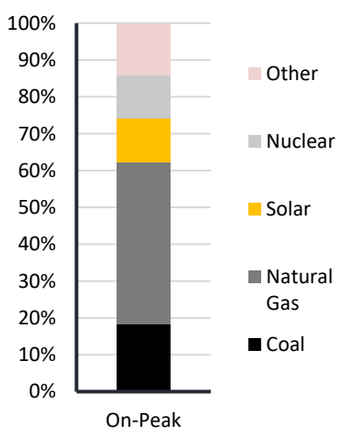
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast).

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level.

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions.

Extreme Derates: Estimated resources unavailable in extreme conditions.

Operational Mitigations: A total of 2.1 GW based on operational/emergency procedures.



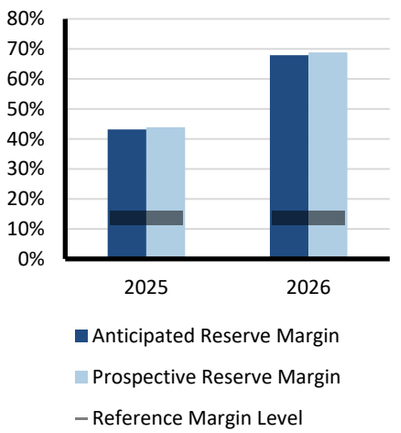
Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,460 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

Highlights

- Given an Anticipated Reserve Margin of 67.9% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves for the August peak load hour given expected normal system summer conditions.
- Continued growth in load and intermittent resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads are high.
- The probability of an EEA during the expected August (and summer) peak load day continues to drop relative to previous SRAs due to continued robust growth in battery energy storage capacity (up 2,677 MW year-on-year as of March 2026). The EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 0.43%, down from 3.1% previously.
- The projected EEA risk does not account for regional constraints in Far West Texas, which may lead to a reliance on price-responsive demand in certain low-generation scenarios.
- An identified risk is the potential of newly interconnected large loads (mainly data centers and crypto-mining facilities) to trip and potentially cause grid stability problems. ERCOT has implemented mandatory ride-through capabilities and requires dynamic model submissions, among other solutions, to address this risk.
- The risk assessment process for this SRA will be the same as ERCOT's upcoming August 2026 Monthly Outlook of Resource Adequacy (MORA) to be released on June 5.

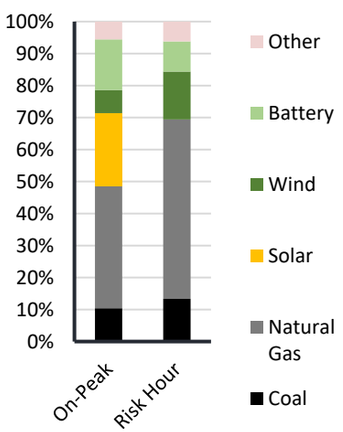
On-Peak Reserve Margin



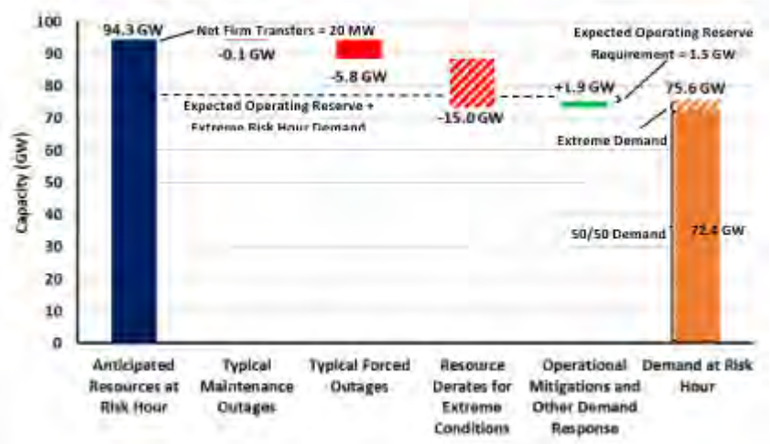
Risk Scenario Summary

The risk of having to declare an EEA for hour 21 is low (0.43%), according to ERCOT's probabilistic reserve risk model (PRRM) simulation results. The highest risk hour for the peak load day in August (which is also the expected summer peak load day).

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Hour: The highest risk hour, HE 2100 (9:00 pm CDT).

Demand Scenarios: Net internal demand, and an adjustment to extreme demand based on the 95th percentile of the PRRM's distribution of load simulation outcomes for the highest-risk hour (HE 2100).

Forced Outages: The adjustment is the 95th percentile of 10,000 daily thermal forced outage values generated by the PRRM, less the 50th percentile value.

Low-Wind Scenario: The adjustment is the 50th percentile of 10,000 wind generation values for hour ending 2100 generated by the PRRM, less the 0th percentile value.

Extreme Derates: The adjustment is the 50th percentile of 10,000 solar generation values for hour ending 2100 generated by the PRRM, less the 0th percentile value.

Operational Mitigations: Additional capacity from switchable generation and additional imports.



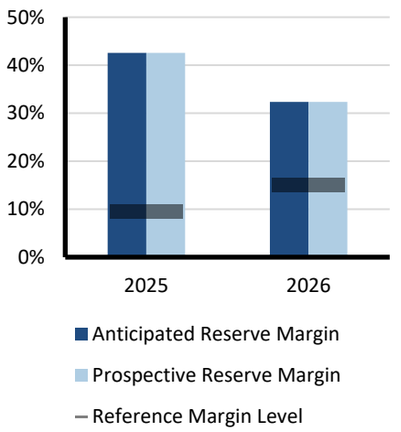
WECC-Alberta

WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's planning entity and RC responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta's transmission system has three interties with neighboring areas—Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. Additionally, WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Peak demand is projected to increase by 2.1% over last summer's forecast.
- Wide-area heat events and wildfires that affect resource and transmission availability across the Western Interconnection are a reliability concern. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability.

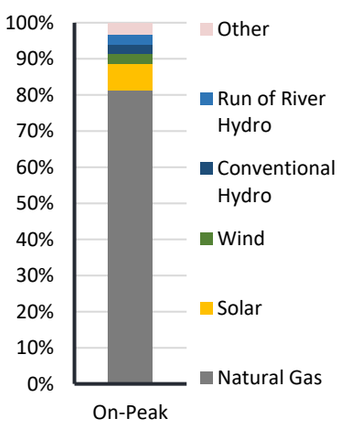
On-Peak Reserve Margin



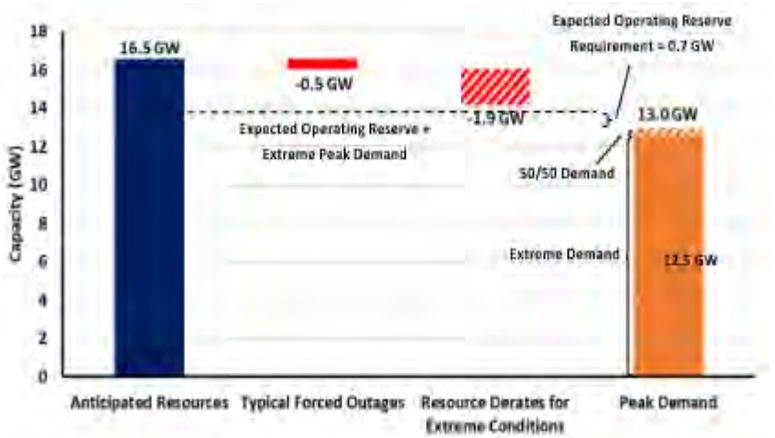
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.



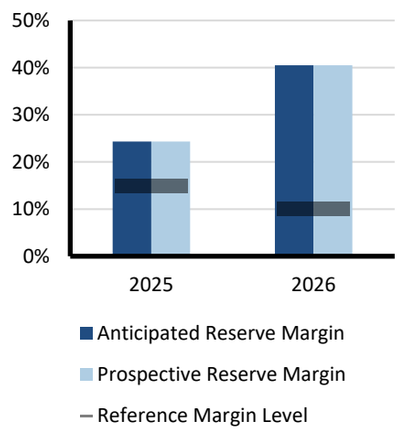
WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern Balancing Authority Area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- WECC-Basin has established a 15% Reference Margin Level for the 2026 Summer assessment period.
- Wildfires remain a reliability concern for the region, particularly in areas with remote generation such as remotely located hydro. Mitigation programs such as hardening and public safety shutoff programs are in place.
- Extreme temperatures pose a risk to the area, impacting load levels and renewable variability. WECC-Basin is positioned to rely on imports during such conditions, which also poses a risk of concurrent impacts should neighbors experience similar conditions.
- Load forecasts for the area are projected to be 2.5% higher than 2025 Summer actuals.
- Wind, solar, and energy storage resources continue to grow.
- Reserve margins are not anticipated to fall below the 15% Reference Margin Level for 2026 Summer. Both Anticipated and Prospective Reserve Margins are expected to be adequate at 37.6%

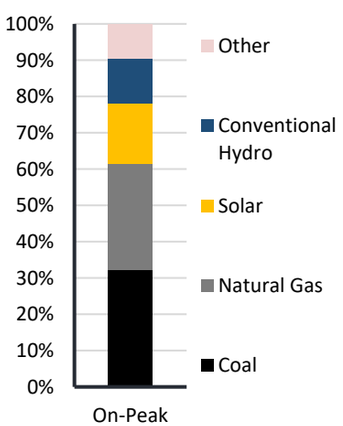
On-Peak Reserve Margin



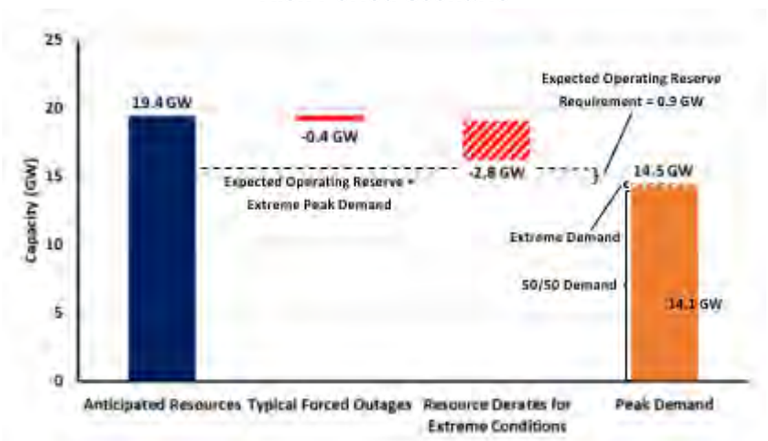
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios with imports.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.



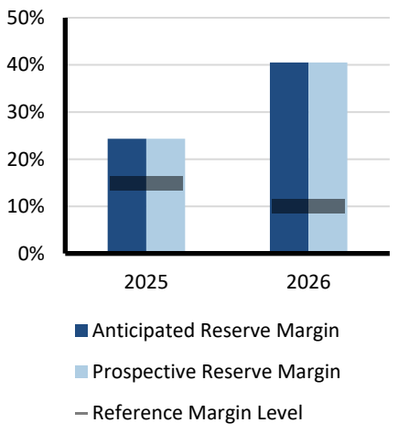
WECC-British Columbia

WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and RC for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia BES and its interconnections. BC Hydro operates an integrated system supported by 32 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro's transmission system has two interties with neighboring areas—the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during the winter season.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-recommended Reference Margin Level.
- WECC's probabilistic analysis shows no LOLH nor EUE under a range of demand and energy availability conditions.
- Peak net internal demand is projected to increase 2.4% over last summer's forecast while anticipated resources increase by 15.7%.
- Wide-area heat events or wildfires that affect resource and transmission availability across the Western Interconnection are a reliability concern. Energy imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.

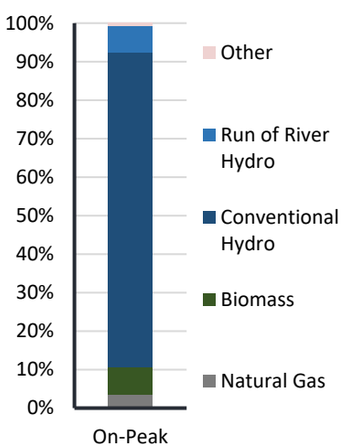
On-Peak Reserve Margin



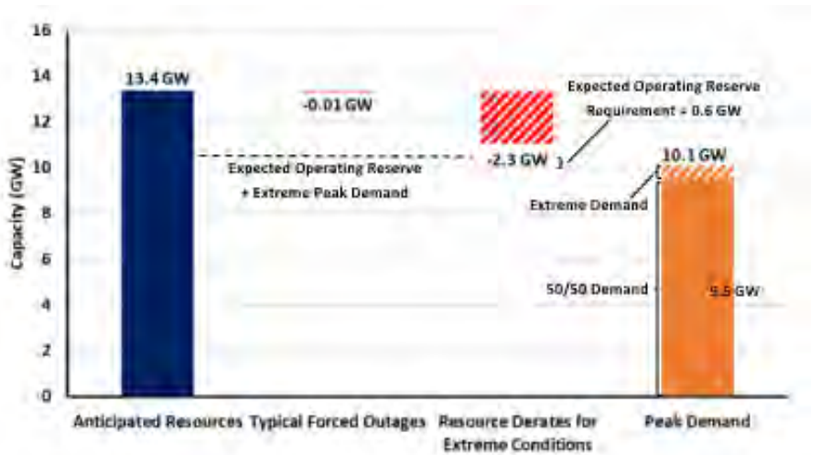
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.



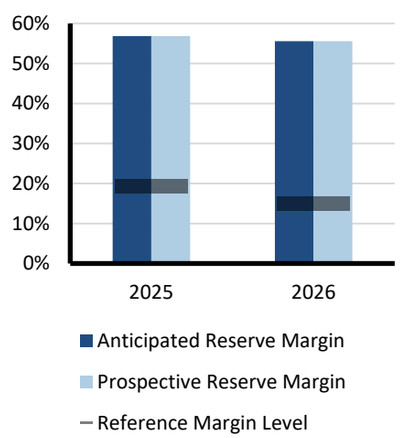
WECC-California

WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, the Los Angeles Department of Water and Power, the Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Extreme heat and wildfires exacerbated by continued climate change may impact generation and transmission resources and remain a reliability concern.
- Cyber attacks pose significant reliability concerns for the area.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- Inverter-based resource (IBR) output variability remains a concern, such as from the evening ramp requirements from declining solar and Santa Ana winds, which can overspeed wind turbines, requiring them to curtail.

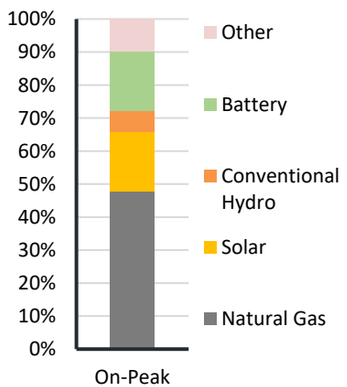
On-Peak Reserve Margin



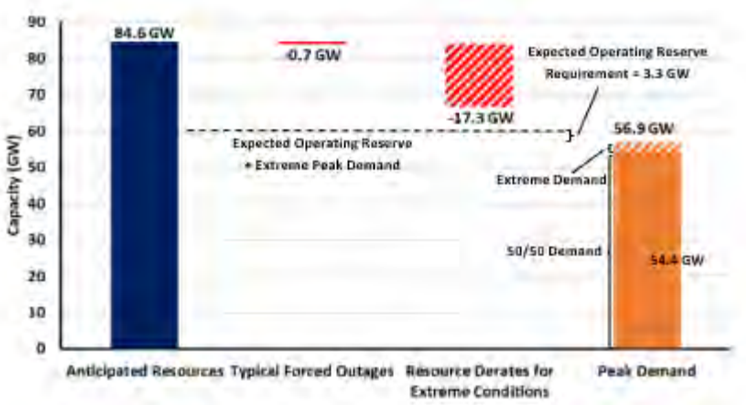
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: On-peak risk scenario.

Demand Scenarios: 50/50 and 90/10. Significant difference in delta from 2025. May be from switch to SERVM and weather year adjustment taken out.

Forced Outages: Based on historical average of forced outages for a specified period/conditions (e.g., average of forced outages for June through September weekdays, over the past three years), or area-specific methodology for determining anticipated forced outages for non-intermittent resources (e.g., thermal, hydro).

Extreme Derates: Capacity derate for resources for extreme conditions. The derate accounts for reduced capacity contributions due to performance in extreme conditions for thermal, wind, PV, storage, and other.



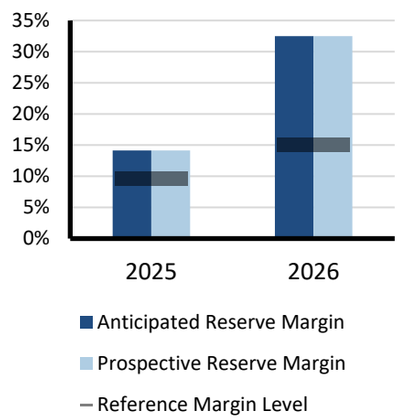
WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes Centro Nacional de Control de Energía (CENACE). It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- WECC-Mexico has added an additional 1 GW of natural-gas-fired resources since last summer, greatly improving its outlook from the *2025 SRA*.
- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions. Anticipated resources are projected to be 15.5% higher.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EEA and a request for assistance from RC West.
- Some generating units have reached advanced operational age, resulting in an observable increase in the forced outage rate. This condition increases the risk of capacity shortfalls and may compromise system reliability during peak seasonal demand.

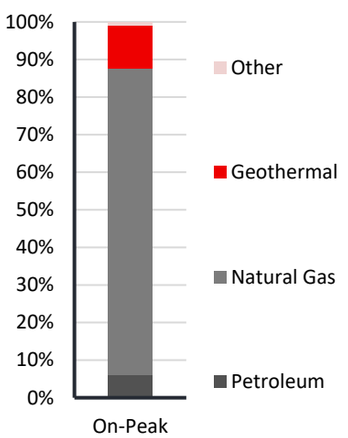
On-Peak Reserve Margin



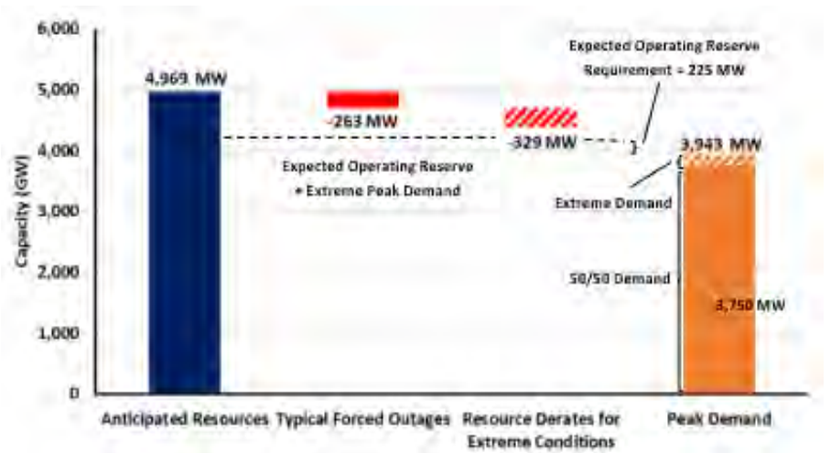
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: Using (90/10) resource performance distribution at peak hour.



WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

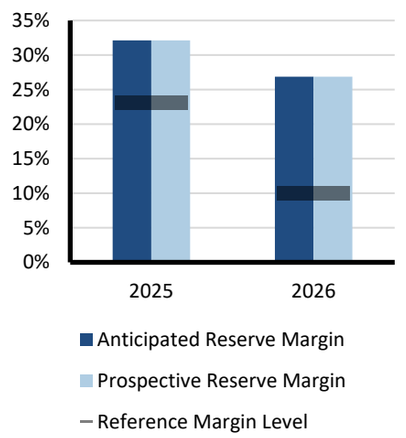
Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions.
- The EUE and LOLH occurs in hours 17 and 18 in August and September, with the vast majority September hour 18.
- Peak net internal demand is projected to grow 4.6% over last summer's forecasts; however, anticipated resources are showing just a 1.5% increase in energy availability, leading to tighter margins.
- Wide-area heat events, wildfires, and low snow-water equivalents due to a changing climate impact generation resource and transmission availability and remain a continued reliability concern. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads or derates, limiting energy availability.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- There have been instances where operators had difficulty maintaining frequency due to sudden disconnection of large loads necessitating additional regulation capability.

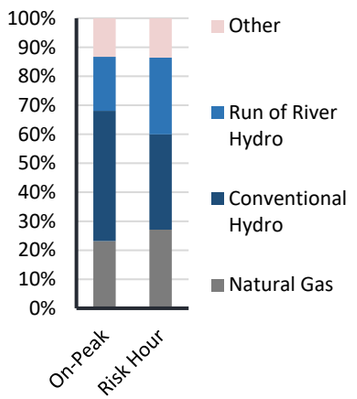
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under the assessed extreme scenarios. WECC's probabilistic analysis showed EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions, placing the area at risk of shortfall during extreme conditions.

On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Modeled output depicting load-loss event from the probabilistic model.

Risk Period: Off-peak highest risk hour is primarily 6 p.m. in September.

Demand Scenarios: Modeled load for the risk hour during load-loss event.

Typical Forced Outages: Based on historical average of forced outages for the period.

Extreme Derates: Modeled outage and derates to account for underperformance of resources at the risk hour.

Operational Mitigations: An operational procedure used to mitigate extreme conditions not already included in the margins is the depletion of operating reserves by 1.7 GW. WECC did not use an operational model prior to this year's report, and it the first time the model includes operating reserves of 6% withheld through unserved energy.



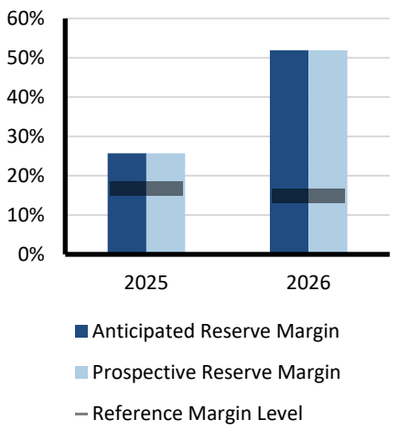
WECC-Rocky Mountain

WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- WECC-Rocky Mountain has established a 15% Reference Margin Level for the 2026 Summer assessment period.
- Anticipated Reserve Margins for the summer exceed the NERC-recommended Reference Margin Level.
- Wildfires in the region, along with extreme heat conditions for the summer, pose the greatest reliability risk scenario for the Rocky Mountains. These conditions can impact rural co-ops disproportionately.
- The existing certain and Anticipated Reserve Margins are projected to be at 43% and 52%, respectively, above the established 15% for the summer. Projections for summer load indicate minimal growth from 2025 and are 0.6% higher than 2025 Summer peak load conditions.

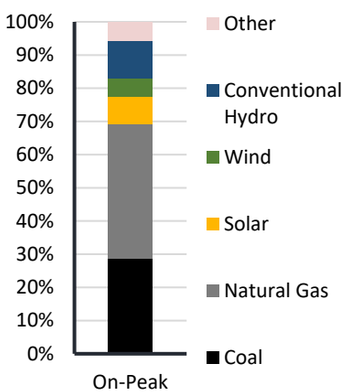
On-Peak Reserve Margin



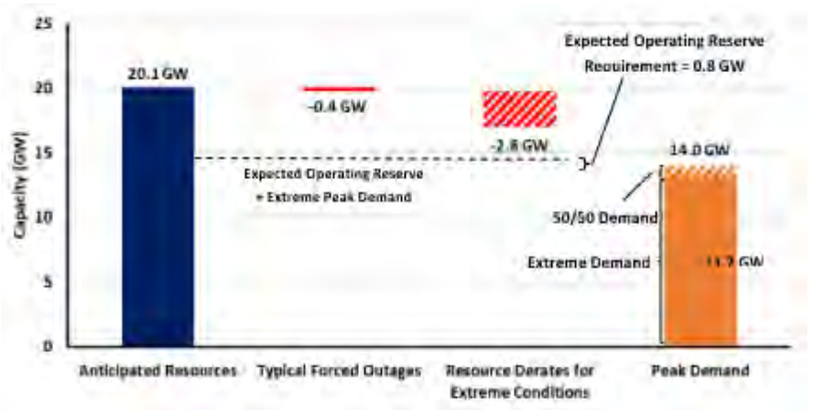
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.



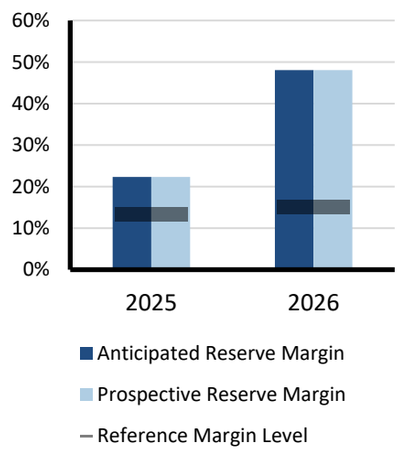
WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Peak net internal demand is projected to grow 9.5% over last summer's forecasts. DR availability has also increased from 199 MW to 364 MW.
- Anticipated resource capacity is expected to be 32.5% higher than last summer, mostly due to methodological changes to capacity of incoming future resources. Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- Elevated forced outage rates due to the amount of aging generation capacity along with extensive overhaul requirements can keep resources out of service for extended periods of time.
- Extreme heat events can result in prolonged periods of elevated demand, derates to thermal generation, and—given the large area that heat waves cover—drastically reduced import capability from neighboring areas. The area also faces significant wildland fire potential this summer. Wildfires have the potential to interrupt large numbers of customers by damaging generation, transmission, and distribution assets.

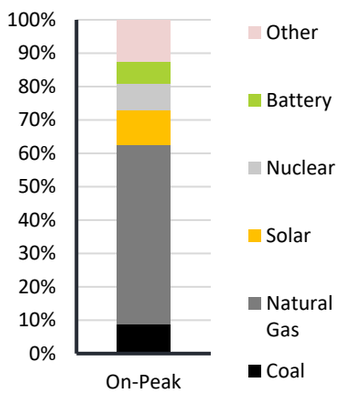
On-Peak Reserve Margin



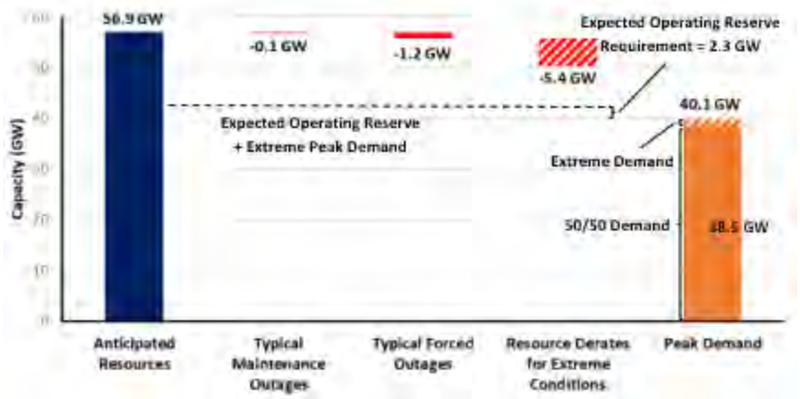
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local).

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: Using (90/10) scenario.

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[17] or total internal demand for the summer and winter of each year.[18]
• Total internal demand projections are based on normal weather (50/50 distribution)[19] and are provided on a coincident[20] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.

[17] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[18] The summer season represents June–September and the winter season represents December–February.

[19] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[20] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Resource Assumptions

Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecast. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Level s may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[21] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for Summer 2026 as shown in **Figure 5**.

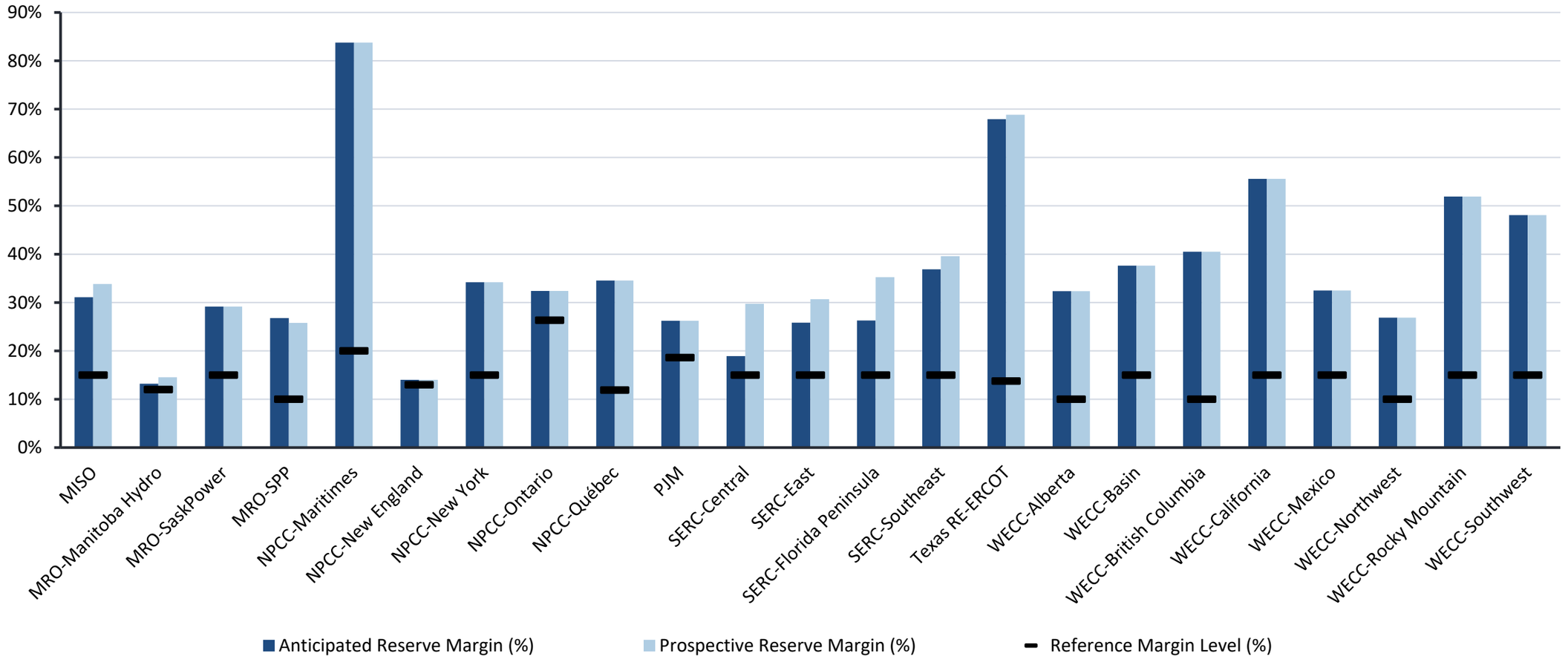


Figure 5: Summer 2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[21] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year to Year

Figure 6 provides the relative change in the forecast Anticipated Reserve Margins from the 2025 Summer to the 2026 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the **Data Concepts and Assumptions** and **Regional Assessments Dashboards** sections.

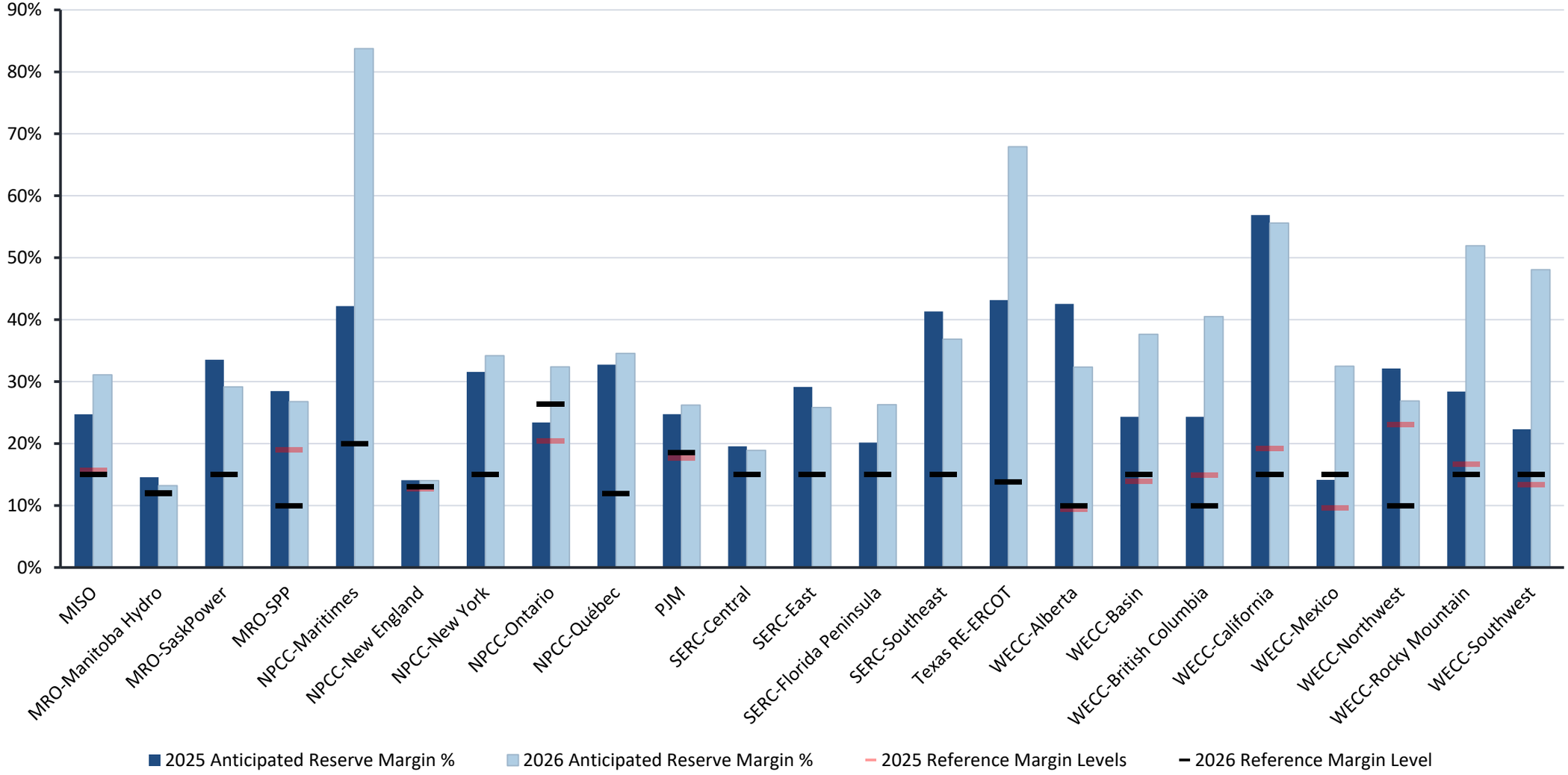


Figure 6: Summer 2025 and Summer 2026 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in **Figure 7**.[22] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

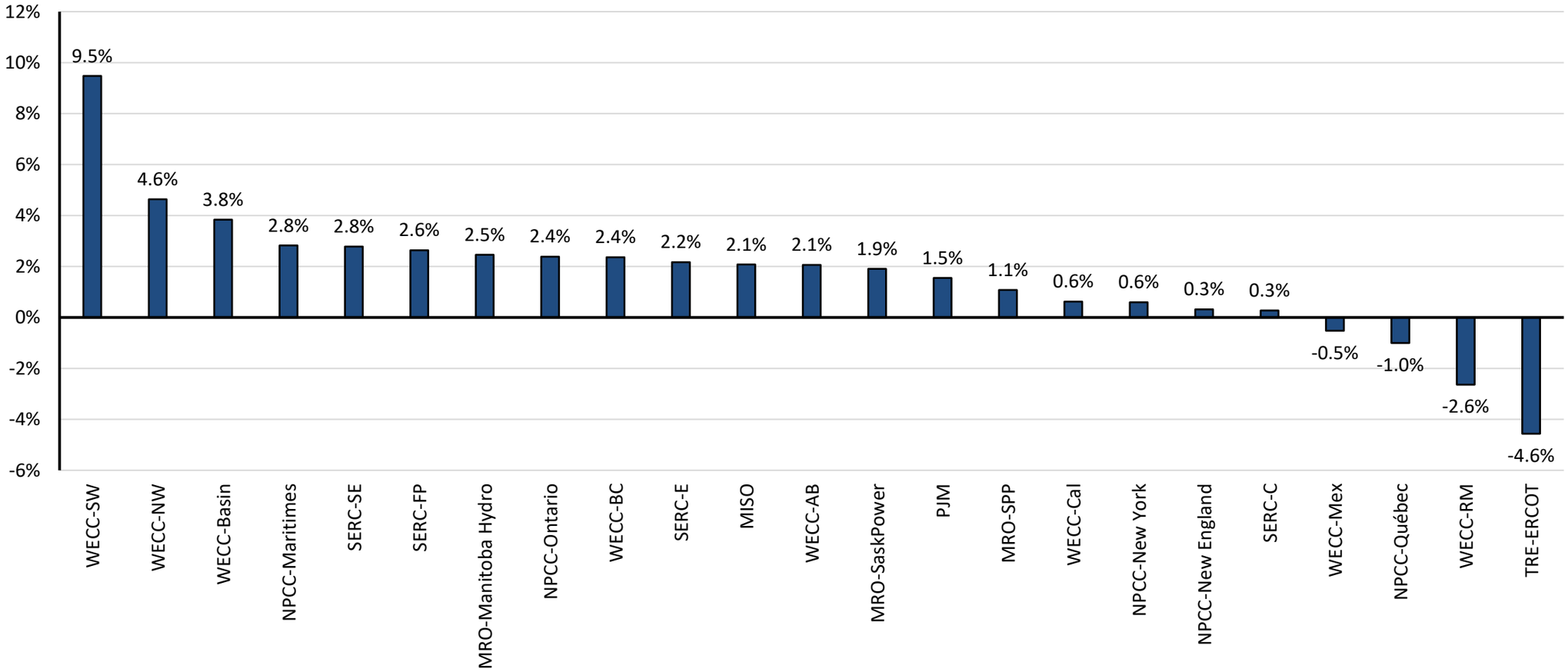


Figure 7: Changes in Net Internal Demand—Summer 2025 Forecast Compared to Summer 2026 Forecast

[22] The lower demand forecast in Texas RE-ERCOT is the result of updated load modeling that reflects the observed behavior of load during peak periods and more demand response from large computational loads.

Demand and Resource Tables

The tables in this section contain peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area.

MISO			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	125,313	127,824	2.0%
Demand Response: Available	9,004	9,100	1.1%
Net Internal Demand	116,309	118,725	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	142,793	152,382	6.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,280	3,259	42.9%
Anticipated Resources	145,073	155,641	7.3%
Existing-Other Capacity	1,190	0	-100.0%
Prospective Resources	148,543	158,900	7.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.7%	31.1%	6.4
Prospective Reserve Margin	27.7%	33.8%	6.1
Reference Margin Level	15.7%	15.0%	-0.7

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,377	3,611	6.9%
Demand Response: Available	0	151	-
Net Internal Demand	3,377	3,460	2.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,583	5,631	0.9%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,714	-1,714	0.0%
Anticipated Resources	3,869	3,917	1.2%
Existing-Other Capacity	21	46	114.6%
Prospective Resources	3,890	3,963	1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.6%	13.2%	-1.4
Prospective Reserve Margin	15.2%	14.5%	-0.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,620	3,688	1.9%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,570	3,638	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,477	4,409	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,767	4,699	-1.4%
Existing-Other Capacity	0	0	-
Prospective Resources	4,767	4,699	-1.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.5%	29.2%	-4.4
Prospective Reserve Margin	33.5%	29.2%	-4.4
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,168	57,122	1.7%
Demand Response: Available	1,408	1,772	25.8%
Net Internal Demand	54,760	55,350	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,549	69,317	-1.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-201	851	-524.0%
Anticipated Resources	70,348	70,168	-0.3%
Existing-Other Capacity	0	0	-
Prospective Resources	69,801	69,621	-0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.5%	26.8%	-1.7
Prospective Reserve Margin	27.5%	25.8%	-1.7
Reference Margin Level	19.0%	10.0%	-9.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,584	3,691	3.0%
Demand Response: Available	327	342	4.6%
Net Internal Demand	3,257	3,349	2.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,348	5,721	31.6%
Tier 1 Planned Capacity	220	280	27.3%
Net Firm Capacity Transfers	63	153	142.9%
Anticipated Resources	4,631	6,154	32.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,631	6,154	32.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.2%	83.8%	41.6
Prospective Reserve Margin	42.2%	83.8%	41.6
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,471	31,578	0.3%
Demand Response: Available	1,487	1,415	-4.8%
Net Internal Demand	29,984	30,163	0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,682	37,324	-1.0%
Tier 1 Planned Capacity	0	210	-
Net Firm Capacity Transfers	1,769	2,941	66.3%
Anticipated Resources	39,451	40,475	2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	39,451	40,475	2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.6%	34.2%	2.6
Prospective Reserve Margin	31.6%	34.2%	2.6
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,202	25,228	0.1%
Demand Response: Available	399	346	-13.3%
Net Internal Demand	24,803	24,882	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,054	27,667	2.3%
Tier 1 Planned Capacity	0	295	-
Net Firm Capacity Transfers	1,245	409	-67.1%
Anticipated Resources	28,299	28,371	0.3%
Existing-Other Capacity	668	0	-100.0%
Prospective Resources	28,967	28,371	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	14.0%	-0.1
Prospective Reserve Margin	16.8%	14.0%	-2.8
Reference Margin Level	12.7%	13.0%	0.3

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,955	22,545	2.7%
Demand Response: Available	998	1,088	9.1%
Net Internal Demand	20,957	21,457	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	24,760	26,837	8.4%
Tier 1 Planned Capacity	413	670	62.2%
Net Firm Capacity Transfers	689	900	30.6%
Anticipated Resources	25,862	28,407	9.8%
Existing-Other Capacity	0	0	-
Prospective Resources	25,862	28,407	9.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.4%	32.4%	9.0
Prospective Reserve Margin	23.4%	32.4%	9.0
Reference Margin Level	20.5%	26.3%	5.9

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,283	22,490	-3.4%
Demand Response: Available	1,020	450	-55.9%
Net Internal Demand	22,263	22,040	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	32,132	33,324	3.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,582	-3,670	42.1%
Anticipated Resources	29,550	29,655	0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	29,550	29,655	0.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	32.7%	34.5%	1.8
Prospective Reserve Margin	32.7%	34.5%	1.8
Reference Margin Level	11.9%	11.9%	0.0

SERC-Central			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,765	44,369	3.8%
Demand Response: Available	864	2,354	172.3%
Net Internal Demand	41,900	42,016	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	46,949	47,603	1.4%
Tier 1 Planned Capacity	592	202	-66.0%
Net Firm Capacity Transfers	2,554	2,158	-15.5%
Anticipated Resources	50,095	49,962	-0.3%
Existing-Other Capacity	2,475	4,546	83.7%
Prospective Resources	52,570	54,508	3.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.6%	18.9%	-0.6
Prospective Reserve Margin	25.5%	29.7%	4.3
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	154,144	156,373	1.4%
Demand Response: Available	7,898	7,864	-0.4%
Net Internal Demand	146,246	148,509	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	186,638	188,854	1.2%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-4,200	-1,427	-66.0%
Anticipated Resources	182,438	187,427	2.7%
Existing-Other Capacity	0	0	-
Prospective Resources	178,238	187,427	5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.7%	26.2%	1.5
Prospective Reserve Margin	21.9%	26.2%	4.3
Reference Margin Level	17.7%	18.6%	0.9

SERC-East			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	44,015	44,765	1.7%
Demand Response: Available	1,558	1,387	-11.0%
Net Internal Demand	42,457	43,378	2.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	54,665	54,637	0.0%
Tier 1 Planned Capacity	17	23	36.9%
Net Firm Capacity Transfers	150	119	-20.7%
Anticipated Resources	54,832	54,780	-0.1%
Existing-Other Capacity	2,628	3,890	48.1%
Prospective Resources	57,459	58,670	2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.1%	26.3%	-2.8
Prospective Reserve Margin	35.3%	35.3%	0.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,987	54,477	2.8%
Demand Response: Available	3,158	3,335	5.6%
Net Internal Demand	49,829	51,142	2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	59,395	64,163	8.0%
Tier 1 Planned Capacity	102	58	-43.4%
Net Firm Capacity Transfers	381	131	-65.6%
Anticipated Resources	59,878	64,352	7.5%
Existing-Other Capacity	3,482	2,481	-28.7%
Prospective Resources	63,360	66,833	5.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	25.8%	5.7
Prospective Reserve Margin	27.2%	30.7%	3.5
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	85,151	83,224	-2.3%
Demand Response: Available	3,292	5,100	54.9%
Net Internal Demand	81,859	78,124	-4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	112,321	125,975	12.2%
Tier 1 Planned Capacity	4,854	5,189	6.9%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	117,195	131,184	11.9%
Existing-Other Capacity	0	0	-
Prospective Resources	117,770	131,903	12.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	43.2%	67.9%	24.8
Prospective Reserve Margin	43.9%	68.8%	25.0
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	47,049	48,625	3.3%
Demand Response: Available	1,338	1,642	22.7%
Net Internal Demand	45,711	46,983	2.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	64,111	64,391	0.4%
Tier 1 Planned Capacity	0	375	-
Net Firm Capacity Transfers	489	-467	-195.5%
Anticipated Resources	64,600	64,299	-0.5%
Existing-Other Capacity	1,077	1,277	18.7%
Prospective Resources	65,676	65,576	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	41.3%	36.9%	-4.5
Prospective Reserve Margin	43.7%	39.6%	-4.1
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,246	12,499	2.1%
Demand Response: Available	0	0	-
Net Internal Demand	12,246	12,499	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,176	16,179	-5.8%
Tier 1 Planned Capacity	281	323	15.1%
Net Firm Capacity Transfers	0	40	-
Anticipated Resources	17,457	16,542	-5.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,457	16,542	-5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.6%	32.3%	-10.2
Prospective Reserve Margin	42.6%	32.3%	-10.2
Reference Margin Level	9.4%	15.0%	5.6

WECC-BC			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,309	9,529	2.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,309	9,529	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,313	12,307	8.8%
Tier 1 Planned Capacity	260	469	80.3%
Net Firm Capacity Transfers	0	612	-
Anticipated Resources	11,573	13,388	15.7%
Existing-Other Capacity	0	0	-
Prospective Resources	11,573	13,388	15.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	40.5%	16.2
Prospective Reserve Margin	24.3%	40.5%	16.2
Reference Margin Level	14.9%	10.0%	-4.9

WECC-California			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,797	55,073	0.5%
Demand Response: Available	746	685	-8.2%
Net Internal Demand	54,051	54,388	0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	75,726	78,788	4.0%
Tier 1 Planned Capacity	8,470	2,085	-75.4%
Net Firm Capacity Transfers	598	3,751	527.2%
Anticipated Resources	84,794	84,623	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	84,794	84,623	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	56.9%	55.6%	-1.3
Prospective Reserve Margin	56.9%	55.6%	-1.3
Reference Margin Level	19.2%	15.0%	-4.2

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	35,321	38,814	9.9%
Demand Response: Available	199	364	82.9%
Net Internal Demand	35,122	38,451	9.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,300	46,476	15.3%
Tier 1 Planned Capacity	1,966	6,667	239.1%
Net Firm Capacity Transfers	695	3,791	445.4%
Anticipated Resources	42,961	56,934	32.5%
Existing-Other Capacity	0	0	-
Prospective Resources	42,961	56,934	32.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.3%	48.1%	25.8
Prospective Reserve Margin	22.3%	48.1%	25.8
Reference Margin Level	13.3%	15.0%	1.7

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	29,157	30,479	4.5%
Demand Response: Available	30	2	-93.3%
Net Internal Demand	29,127	30,477	4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	36,388	35,708	-1.9%
Tier 1 Planned Capacity	844	477	-43.5%
Net Firm Capacity Transfers	1,249	2,483	98.8%
Anticipated Resources	38,481	38,668	0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	38,481	38,668	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	32.1%	26.9%	-5.2
Prospective Reserve Margin	32.1%	26.9%	-5.2
Reference Margin Level	23.1%	10.0%	-13.1

WECC-Basin			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	14,214	14,564	2.5%
Demand Response: Available	620	448	-27.7%
Net Internal Demand	13,594	14,116	3.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	14,923	16,759	12.3%
Tier 1 Planned Capacity	704	1,382	96.3%
Net Firm Capacity Transfers	1,274	1,288	1.1%
Anticipated Resources	16,901	19,429	15.0%
Existing-Other Capacity	0	0	-
Prospective Resources	16,901	19,429	15.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	37.6%	13.3
Prospective Reserve Margin	24.3%	37.6%	13.3
Reference Margin Level	14.0%	15.0%	1.0

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,848	13,516	-2.4%
Demand Response: Available	284	310	9.1%
Net Internal Demand	13,564	13,206	-2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,312	18,363	6.1%
Tier 1 Planned Capacity	104	1,206	1059.6%
Net Firm Capacity Transfers	0	495	-
Anticipated Resources	17,416	20,063	15.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,415	20,063	15.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.4%	51.9%	23.5
Prospective Reserve Margin	28.4%	51.9%	23.5
Reference Margin Level	16.7%	15.0%	-1.7

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,770	3,750	-0.5%
Demand Response: Available	0	0	-
Net Internal Demand	3,770	3,750	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,303	4,761	10.6%
Tier 1 Planned Capacity	0	765	-
Net Firm Capacity Transfers	0	-557	-
Anticipated Resources	4,303	4,969	15.5%
Existing-Other Capacity	0	0	-
Prospective Resources	4,303	4,969	15.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	32.5%	18.4
Prospective Reserve Margin	14.1%	32.5%	18.4
Reference Margin Level	9.6%	15.0%	5.4

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (VER) (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution (MW) of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Run-of-River Hydro	Expected Run-of-River Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	32,066	5,611	17%	20,419	12,322	60%	1,294	770	60%	3,560	3,457	97%
MRO-Manitoba Hydro*	259	47	18%	-	-	0%	202	-	0%	-	-	0%
MRO-SaskPower	816	319	39%	30	9	28%	121	74	61%	-	-	0%
MRO-SPP	35,760	8,114	23%	3,926	2,139	54%	113	66	59%	1,318	1,113	84%
NPCC-Maritimes	1,341	423	32%	148	80	54%	1,316	1,316	100%	162	106	65%
NPCC-New England	2,431	424	17%	3,609	1,728	48%	584	287	49%	723	686	95%
NPCC-New York	2,598	417	16%	661	283	43%	914	354	39%	23	-	0%
NPCC-Ontario*	4,943	735	15%	478	66	14%	-	-	0%	451	226	50%
NPCC-Québec*	4,024	885	22%	10	1	12%	444	444	100%	-	-	0%
PJM	13,855	4,570	33%	16,852	9,951	59%	2,505	2,505	100%	256	238	93%
SERC-Central	1,324	370	28%	2,303	1,446	63%	4,979	3,213	65%	100	100	100%
SERC-East	-	-	0%	7,843	4,205	54%	3,096	3,033	98%	323	235	73%
SERC-Florida Peninsula	-	-	0%	13,502	6,276	46%	-	-	0%	1,177	1,145	97%
SERC-Southeast	-	-	0%	9,412	8,087	86%	3,326	3,374	101%	164	141	86%
Texas RE-ERCOT	40,586	9,450	23%	40,279	29,682	74%	579	447	77%	21,979	20,688	94%
WECC-AB	5,684	455	8%	1,870	1,271	68%	896	481	54%	261	222	85%
WECC-Basin	5,959	360	6%	3,773	2,605	69%	884	386	44%	655	557	85%
WECC-BC*	753	60	8%	17	12	71%	1,871	888	47%	-	-	0%
WECC-Cal	7,985	907	11%	27,495	14,278	52%	1,120	628	56%	16,711	14,204	85%
WECC-Mexico	296	3	1%	350	35	10%	-	-	0%	-	-	0%
WECC-NW*	9,941	1,016	10%	1,729	1,051	61%	14,086	8,303	59%	547	461	84%
WECC-RM	5,684	1,034	18%	2,920	1,551	53%	117	61	52%	342	291	85%
WECC-SW	4,848	1,473	30%	11,112	4,868	44%	376	270	72%	3,691	3,137	85%
EASTERN INTERCONNECTION	94,474	21,180	22%	78,714	46,528	59%	18,892	15,435	82%	7,805	7,220	92%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	1	12%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,586	9,450	23%	40,279	29,682	74%	579	447	77%	21,979	20,688	94%
WECC INTERCONNECTION[23]	41,150	5,308	13%	49,266	25,670	52%	19,350	11,017	57%	22,207	18,872	85%
All INTERCONNECTIONS	**181,153**	**36,673**	**20%**	**168,736**	**101,946**	**60%**	**38,822**	**26,899**	**69%**	**52,442**	**47,005**	**90%**

*On peak contributions from conventional hydro are not represented in this table, and in certain areas those contributions are significant.

[23] Some areas in the Western Interconnection re-categorized their hydro resources for the 2026 SRA from run-of-river hydro to conventional hydro

Review of 2025 Capacity and Energy Performance

The summer of 2025 was the 12th hottest on record for the contiguous United States[24] during the meteorological summer period (June–August) and the 11th warmest summer in Canada.[25] Cooler-than-normal temperatures were observed in the eastern U.S., whereas most of Canada experienced slightly above-normal temperatures. Despite the comparatively temperate 2025 Summer (summer of 2024 was the fourth-hottest on record in both the United States[26] and Canada[27]), U.S. electricity generation reached a record high for the assessment summer period (June – September) at 1,628 TWh[28], topping the prior year's summer electricity generation total of 1,603 TWh. The month of July in the U.S. set a new monthly generation record at 446 TWh. In Canada, the comparatively cooler summer appears to have brought electricity generation down from the 2024 summer high of 192 TWh to the 2025 total of 188 TWh[29]. Actual peak demand exceeded normal demand forecasts across 19 assessment areas and exceeded extreme demand projections from the *2025 SRA* in three assessment areas. Despite a lower average summer temperature in 2025, a widespread heatwave[30] in early summer impacted much of the central and eastern U.S., bringing record-setting temperatures across several hundred counties.

Canada experienced its second-worst wildfire year on record[31] (2023 being the worst) with fires burning an area larger than New Brunswick and Prince Edward Island combined. Saskatchewan and Manitoba comprised nearly half of the total area impacted by the fires. Drought that began in 2021 has also deepened across Canada, resulting in reduced hydroelectric power generation for a third straight year in British Columbia.

Eastern Interconnection–Canada and Québec Interconnection

In Ontario, grid operators utilized demand response resources on 10 different occasions during the summer period,[32] culminating in demand reductions of 316 MW during the time of peak demand (24,862 MW) on June 24, 2025, the single highest peak in 12 years. Other demand-side management programs further reduced peak demand by 1,800 MW, contributing to 7% total reduction in demand stemming from consumer programs.

Québec saw electricity generation of roughly 52 TWh during the summer period,[33] down from 56 TWh for Summer 2024 amid relatively cooler temperatures and a year beset by low runoff levels that have persisted since 2023.[34] The Maritimes saw a slight increase in electricity generation to 5.8 TWh for Summer 2025, up from 5.3 TWh the prior summer. Nova Scotia Power realized nearly a 20% reduction in annual 2025 power outages from the year before but still fell short of targets set by the Nova Scotia Energy Board relating to power-outage duration and frequency.

Saskatchewan saw severe storms and large hail in late August that damaged infrastructure, triggering emergency operating conditions and power outages.[35]

[24] Assessing the U.S. Temperature and Precipitation Analysis in August 2025 | News | National Centers for Environmental Information (NCEI)
[25] Climate Trends and Variations Bulletin - summer 2025 - Canada.ca
[26] U.S. sweltered through its 4th-hottest summer on record | National Oceanic and Atmospheric Administration
[27] Climate Trends and Variations Bulletin - Summer 2024 - Canada.ca
[28] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis
[29] Electric power generation, monthly generation by type of electricity
[30] Assessing the U.S. Climate in June 2025 | News | National Centers for Environmental Information (NCEI)
[31] Canada's top 10 weather stories of 2025 - Canada.ca
[32] 2025 Year in Review
[33] Electric power generation, monthly generation by type of electricity
[34] Hydro-Québec - Quarterly Bulletin - Third Quarter 2025
[35] SaskPower crews still working to restore power after weekend outages - WestCentralOnline: West Central Saskatchewan's latest news, sports, weather, community events.

Eastern Interconnection–United States

New York and New England saw region-wide heat waves in June and July. ISO-NE saw peak-hour demand in June exceed its extreme demand projections from the *2024 SRA*, a significant step up from the prior year's summer peak (+7%). Heat and humidity, high demand, and some unexpected generation reductions and outages left the region short of the resources needed to maintain required operating reserves for more than three hours around the evening peak on June 24,[36] though electricity supply was not interrupted. NYISO declared an EEA Level 1 on June 24, June 25, and July 29 due to limited capacity availability,[37] resulting in the deployment of emergency DR programs and other special-case resources. Both the New York and New England ISOs saw peak loads that exceeded their demand projections.

PJM saw their third-highest all-time summer peak[38] of more than 160 GW. This exceeded extreme demand projections for the summer (159 GW). The system operator was able to manage load by calling on customers who were enrolled in financially incentivized DR programs.

MISO declared an EEA Level 1[39] on June 23 to access emergency capacity. At the time of the event, more than 4 GW of generation was trapped in the south due to transmission constraints. MISO was able to dispatch 565 MW of emergency capacity in the Midwest, but only 45% performed. MISO has been engaged in efforts to highlight the need for non-performance penalties. On June 24, when neighboring areas were experiencing peak demand, MISO had to curtail non-firm exports to avoid going into EEA. In late July, MISO experienced a shortage of operating reserves due to errors in forecasting load and renewables. This was one of 24 total instances of operating reserve shortage, double the amount from the previous year.

In SERC, an EEA Level 2 was declared in the Carolinas amid high load conditions and generation resources that were unavailable[40] during the peak of the June heat wave affecting the broader Eastern Interconnection – a precautionary reliability measure to support system operations during peak demand and generation outages. During this event, the affected service territory recorded a new all-time peak demand of 21,931 MW on June 25.

Texas Interconnection–ERCOT

Texas saw a relatively mild summer and above-average rainfall in 2025 with the June–July period ranking as the 43rd hottest out of 131 historical years. But even so, Summer 2025 load levels were comparable to the 2023 Summer load levels when the summer was far hotter.[41] Forced outages of thermal resources outstripped such forced outages from the summer of 2024, prompting a larger discharge of energy storage resources (ESR) some evenings. Texas set a new solar generation record in July at 29.3 GW, and solar contributed just under 17 GW at the hour of peak demand on August 18 (hour ending at 6:00 pm). Wind generation was relatively high at the peak demand hour and also set records in the spring. Energy storage also reached a new discharge record at 7.2 GW on August 20.

Western Interconnection

The Western Interconnection saw summer peak demand decrease slightly from the previous year's summer peak, reaching 163,140 MW in 2025, down from 168,206 MW the prior summer. Operators and RCs were able to maintain the flow of electricity through the summer months.

[36] Summer 2025 recap: Reliability maintained as grid sees highest peak in over a decade - ISO Newswire
[37] NYISO Summer 2025
[38] 2025 in Review: Operations Improvements See PJM Through Record Peaks, Growing Demand | PJM Inside Lines
[39] Microsoft PowerPoint - IMM Quarterly Report, Summer 2025
[40] DOE grants Duke Energy authority to exceed power plant permit limits during extreme heat | Utility Dive
[41] 12 Summer 2025 Operational and Market Review.pptx

Western Interconnection–Canada

Western Canada experienced a heat wave from late August and through early September, breaking daily records in British Columbia and the Yukon and exacerbating the ongoing drought in western Canada. Wildfire activity also increased due to heat and dry conditions. The same period brought generation outages that triggered emergency operations in parts of western Canada.

Western Interconnection–United States

The western United States overall navigated last summer with the BPS experiencing relatively few emergency events, and demand in western assessment areas never reached or exceeded the projections for extreme demand from the *2025 SRA.* Variable resources performed as expected with the exception of California seeing much less solar generation than anticipated, 65% less solar than was projected ahead of the prior year's assessment. California's lower-than-expected solar did not result in energy shortfalls.

In Mexico, generation losses in late August triggered Level 3 EEAs, but the overall number of Level 3 EEAs was down year-on-year and on par with the number of Level 3 EEAs triggered in 2023 for the same seasonal period.

Despite the moderation in summer heat when compared to 2024, certain Rocky Mountain states saw record temperatures with Utah and Nevada recording their warmest years on record. The Rocky Mountain region saw peak demand surpass the projected normal demand conditions but remained under extreme demand projections.

2025 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	121.6	116.3 121.6	1,105	6,039	12,323	9,123	8,856
MRO-Manitoba Hydro	3.5	3.4 3.6	0	48	0	0	252
MRO-SaskPower	3.6	3.6 3.8	232	310	26	9	0
MRO-SPP	54.5	54.8 57.5	8,130	5,556	810	492	4,370
NPCC-Maritimes	3.6	3.3 3.5	151	314	69	0	33
NPCC-New England	26.6	24.7 26.4	566	142	180	1,412	1,963
NPCC-New York	32	30.0 31.7	1,256	446	164	243	1,372
NPCC-Ontario	24.9	21.0 24.5	607	742	39	66	1,532
NPCC-Québec	23.0	22.3 23.3	790	885	0	0	5,029
PJM	160.7	146.2 158.7	4,515	1,855	7,730	6,244	15,945
SERC-C	43.2	41.9 45.7	84	370	714	1,053	701
SERC-E	44.8	42.5 45.7	0	0	3,200	5,022	2,407
SERC-FP	54.6	49.8 50.8	0	0	8,035	5,749	1,599
SERC-SE	46.4	45.7 55.9	0	0	3,366	7,728	1,380
TRE-ERCOT	83.7	85.2[5] 91.3[5]	14,509	9,396	16,961	22,962	11,095
WECC-AB	12.5	12.2 12.7	2,870	796	32	1,480	**
WECC-BC	9.8	9.3 10.0	293	149	4.8	0	**
WECC-CA	54	54.1 64.3	1,744	1,207	5,064	14,756	1,063

2025 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	**Actual Peak Demand[1] (GW)**	**SRA Peak Demand Scenarios[2] (GW)**	**Wind – Actual[1] (MW)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MW)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
WECC-MX	3.5	3.8 4.1	2.5	50	296	227	**
WECC-NW	29.8	29.1 32.7	1,054	3,107	1,398	666	1,825
WECC-RM	13.4	13.8 15.0	2,313	1,359	1,571	1,669	1,954
WECC-Basin	13.8	13.6 15.0	931	911	2,660	2,231	0
WECC-SW	36.9	35.1 39.0	1,230	1,091	4,472	4,293	2,323
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:
[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from the assessment areas.
[2] See NERC *2025 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.
[3] Expected values of wind and solar resources from the *2025 SRA*.
[4] Values from NERC Generator Availability Data System for the 2025 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2025 SRA*.
[5] Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (3.2 GW) to the demand scenarios found on p. 30 of the 2025 SRA.
**Data unavailable - Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit OOO: Department, Order No. 202-26-22 (May 19, 2026)

Department of Energy
Washington, DC 20585

Order No. 202-26-22

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, Michigan. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[3] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order Nos. 202-25-3, 202-25-7, and 202-25-9 issued pursuant to FPA section 202(c), each required that the Campbell Plant remain in operation for 90 days, until August 21, 2025, November 19, 2025, and February 17, 2026, respectively. Subsequently, Order No. 202-26-16, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, through May 18, 2026. Those orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

Specifically, I determined that MISO likely faced tight reserve margins due to well-documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.[4] I determined that the continued operation of the Campbell Plant would provide additional generation capacity during

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] *See* Consumers Energy, *Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation* (June 23, 2021), https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation.

[4] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc., and Consumers Energy Co.*, Order No. 202-25-9, at 1 (Nov. 18, 2025), https://www.energy.gov/sites/default/files/2025-11/Order%20No%20202-25-9.pdf.

these periods, which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.[5] I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability.[6] My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC stated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[7] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply shortfalls. NERC anticipated that the near -term period of greatest capacity shortfall for MISO would likely occur in August.[8]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[9] Additionally, EIA stated, "Michigan's nuclear power plants typically supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[10] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. The Palisades plant remains unavailable, although the plant will reportedly resume service in 2026.[11]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024.

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[5] *Id.* at 5; *see also id.* at 1, 8.

[6] *Id.* at 1.

[7] NERC, *2025 Summer Reliability Assessment*, at 16 (May 2025), https://www.nerc.com/globalassets/programs/rapa/ra/nerc_sra_2025.pdf.

[8] *Id*.

[9] EIA, *Mich. State Profile & Energy Estimates* (Nov. 19, 2025), https://www.eia.gov/states/MI/analysis.

[10] *Id.*

[11] *See* Dustin Dwyer, *Palisades nuclear plant restart plans pushed back to "early 2026,"* MICH. PUB. (Dec. 17, 2025), https://www.michiganpublic.org/environment-climate-change/2025-12-17/palisades-nuclear-plant-restart-plans-pushed-back-to-early-2026; Will Wade, *Despite $80-billion commitment, nuclear plants face decadelong timeline to meet AI energy needs*, L.A. TIMES (Nov. 13, 2025), https://www.latimes.com/business/story/2025-11-13/despite-80-billion-commitment-nuclear-plants-face-decade-long-timeline-to-meet-ai-energy-needs.

Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts, and Consumers acquired a 1,200 MW natural gas power plant in Covert, Michigan, NERC has noted "[e]scalating demand forecasts and uncertainty around new resource commercialization timing contribute to heightened resource adequacy concerns in the MISO area."[12]

Fourth, MISO's Planning Resource Auction Results for the 2025–2026 Planning Year, released in April 2025, noted that for the northern and central zones, which include Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[13] While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance."[14] According to MISO, these results "reinforce the need to increase capacity."[15]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-3, 202-25-7, 202-25-9, and 202-26-16 continue, both in the near and long term.[16] The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the EIA-923 Power Plant Operations Report's monthly generation data for February 2026, the total net generation for the

[12] NERC, *2025 Long-Term Reliability Assessment*, at 15 (Jan. 2026) (2025 NERC Long-Term Reliability Assessment), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[13] MISO, *Planning Resource Auction—Results for Planning Year 2025–2026*, at 13 (May 29, 2025) (MISO 2025–2026 Planning Resource Auction), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

[14] *Id.* at 12.

[15] *Id*. at 2. *See Midcontinent Indep. Sys. Operator, Inc. & Consumers Energy Co.*, Order No. 202-25-7 (Aug. 20, 2025) (determining that emergency conditions existed), https://www.energy.gov/sites/default/files/2025-08/MISO%20Order%20No.%20202-25-7.pdf.

[16] Further, as noted in Order No. 202-25-7, as a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. If Consumers were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Order No. 202-25-7 at 1 n.1.

Campbell Plant was 394,703 MWh and from June 2025 through December 2025 the plant generated an average of approximately 520,670 MWh per month.[17] The historic data of consistent generation indicates the Campbell plant is providing vital generation capacity to the region. From June 11, 2025, through November 5, 2025, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.[18]

MISO's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when it operated under a cold weather alert and declared conservative operations from January 23 through February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 "MaxGen" event for MISO's North and Central Regions due to generational outages, high demand, and transfer capability limits.[19]

MISO's year-round resource adequacy concerns are well documented. In 2021, MISO requested that the Federal Energy Regulatory Commission (FERC) approve its revised resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[20] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern."[21] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[22]

In December 2023, MISO released its *Attributes Roadmap,* in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a

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[17] *See* EIA, Form EIA-923 detailed data with previous form data (EIA-906/920), February 2026 Data (Mar. 2026), https://www.eia.gov/electricity/data/eia923/. On the "Page 1 Generation and Fuel Data" tab, Plant Name filtered for J H Campbell, Rows 533–535.

[18] MISO *Operations Report* (Sept. 16, 2025) cdn.misoenergy.org/20250916%20Markets%20Committee%20of%20the%20BOD%20Item%2005%20MISO%20Operations%20Report717458.pdf

[19] Midcontinent ISO, @MISO_energy, X (Jan. 24, 2026, 9:39 AM), https://x.com/MISO_energy/status/2015072060876140805.

[20] *Midcontinent Indep. Sys. Operator, Inc.*, Transmittal Letter, Docket No. ER22-495-000 (filed Nov. 30, 2021). FERC accepted MISO's proposed tariff revisions on August 31, 2022. *Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (2022), *order on reh'g & compliance*, 182 FERC ¶ 61,096 (2023).

[21] MISO Transmittal Letter at 3.

[22] *Id.* at 3–4.

rapidly transforming energy landscape."[23] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023–2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons.[24] MISO also projected that the risk of loss of load in the winter and spring seasons will nevertheless increase over time, although not as high as in the summer or fall.[25]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, *MISO's Response to the Reliability Imperative*.[26] In a section of that report labeled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[27]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In its 2025 Long-Term Reliability Assessment, NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,[28] stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[29] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[30] Moreover, the 2025 NERC Long-Term Reliability Assessment notes that "MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and

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[23] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[24] *Id.* at 11.

[25] *Id.*

[26] MISO, *MISO's Response to the Reliability Imperative* (updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.

[27] *Id.* at 12.

[28] 2025 NERC Long-Term Reliability Assessment at 6.

[29] *Id.* at 8.

[30] *Id.* at 43.

retirements."[31] The report observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[32] However, NERC also concluded that "risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high."[33]

While the 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027, two earlier winter studies were more critical. The 2023–2024 NERC Winter Reliability Assessment characterized MISO as a region at elevated risk with the "[p]otential for insufficient operating reserves in above-normal conditions."[34] These findings were echoed in NERC's 2024–2025 Winter Reliability Assessment, which noted that "[g]enerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[35]

The evidence indicates that there is also a potential longer-term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025–2026 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[36]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[37] The 2025 OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[38] The 2025 OMS-MISO Survey also projected that there would be insufficient capacity to meet the peak demand for

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[31] *Id.* at 15.

[32] *Id.*

[33] *Id.*

[34] NERC, *2023–2024 Winter Reliability Assessment*, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

[35] NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

[36] MISO 2025–2026 Planning Resource Auction at 13.

[37] OMS & MISO, *OMS-MISO Survey Results* (updated June 6, 2025) (2025 OMS-MISO Survey), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[38] *Id.* at 2.

electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[39] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[40]

The primary reasons for these projected deficits also are shown on the 2025 OMS-MISO Survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[41] Although the 2025 OMS-MISO Survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[42]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[43] MISO's ERAS should help expedite the construction of needed new capacity; however, resources studied under the ERAS will have commercial operation dates that are at least three years away and are provided an additional three-year grace period to commence commercial operations.[44] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[45] Consequently, the

[39] *Id.* at 7.

[40] *Id.* at 9.

[41] *Id.* at 7, 9.

[42] *Id.*

[43] *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 (2025), https://cdn.misoenergy.org/2025-07-21_192%20FERC%20%C2%B6%2061,064_Docket%20No.%20ER25-2454-000709770.pdf.

[44] *Id.* P 84.

[45] *See generally* S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025), https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply. ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts.").

new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-3, 202-25-7, 202-25-9, and 202-26-16 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[46] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[47] In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[48]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[49] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[50] In addition, as just one example, Consumers

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[46] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[47] *Id.*

[48] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[49] U.S. Dep't of Energy, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[50] Ekku Jokinen, *Top 21 A.I. Cos. in Mich.* (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[51]

Grid operators—including MISO itself—have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[52] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[53] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[54]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy . . . or other causes," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in his judgment will best meet the emergency and serve the public

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[51] *See* Data Center Dynamics, *Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center* (Aug. 5, 2025) (quoting Consumers CEO Garrick Rochow), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/.

[52] *Keeping the Lights On: Examining the State of Regional Grid Reliability; Hearing Before the House Committee on Energy and Commerce, Subcommittee on Energy*, 119th Cong. 5 (2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-CurranJ-20250325.pdf.

[53] *Id.* at 6

[54] *Id.* at 7.

interest."[55] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

As described above, the emergency conditions resulting from the combination of increasing demand for electricity and the capacity shortfall stemming from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-3, 202-25-7, 202-25-9, and 202-26-16, will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the increased demand for electricity and mitigate the observed shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes, thus serving the public interest pursuant to FPA section 202(c).

To ensure that the Campbell Plant will be available if needed to address emergency conditions, it shall remain in operation through August 16, 2026.[56]

Based on my determination of an emergency set forth above, I hereby order:

A. From May 19, 2026, MISO and Consumers shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize costs to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

[55] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

[56] 16 U.S.C. § 824a(c)(4).

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees, or purchase offsets or allowances for emissions that occur during the emergency conditions, or to use other geographic or temporal flexibilities available to generators.

D. By June 2, 2026, MISO is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

E. Consumers is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.

H. This Order shall be effective on May 19, 2026, through August 16, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 19th day of May 2026.

Chris Wright

_____

Chris Wright
Secretary of Energy
cc:

FERC Commissioners

Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Michigan Public Service Commissioners

Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit PPP: Department, Order No. 202-26-24 (May 21, 2026)

Department of Energy
Washington, DC 20585

PJM Interconnection, L.L.C. and
Constellation Energy Corp.
Regarding Eddystone Unit 3 and Unit 4

Order No. 202-26-24

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in the PJM Interconnection, L.L.C. (PJM) region due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, Pennsylvania. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order Nos. 202-25-04, 202-25-08, and 202-25-10, issued pursuant to FPA section 202(c), each required that the Eddystone Units remain available to operate for 90 days, until August 28, 2025, November 26, 2025, and February 24, 2026, respectively. Subsequently, Order No. 202-26-17, issued pursuant to FPA section 202(c), required the Eddystone Units to remain available to operate for 90 days, through May 24, 2026. Those orders were based on my determination that emergency conditions existed in the PJM region. Specifically, I explained that there was a potential shortage of electric energy and a shortage of facilities for the generation of electric energy.[3] I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety.[4] I determined that continued operation and economic dispatch of the Eddystone

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] *See, e.g.*, *PJM Interconnection, L.L.C.*, Order No. 202-25-10, at 7 (Nov. 25, 2025).
[4] *Id.* at 9.

Units was necessary to best meet the emergency and serve the public interest.[5] My determination was based on a number of different facts.

First, in congressional testimony, PJM's President and CEO stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.[6] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.[7] Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[8] In its February 2023 assessment, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[9]

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a

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[5] *Id.* at 9 & Ordering Paragraph A.

[6] *Keeping the Lights On: Examining the State of Reg'l Reliability; Hearing Before the House Comm. on Energy & Com., SubComm. on Energy*, 119th Cong. 4–5 (2025) (testimony of Mr. Manu Asthana, President and CEO, PJM) [hereinafter Asthana Test.], https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.

[7] *Id.*; *see also PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) ("PJM states . . . that, in 2023, it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM's interconnection queue pose increasing reliability risks through 2030.").

[8] *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing Risk*, PJM INSIDE LINES (May 9, 2025), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/.

[9] PJM, *Energy Transition in PJM: Res. Rets., Replacements & Risks*, at 1 (Feb. 24, 2023) [hereinafter Four Rs Report], https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[10]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-04, 202-25-08, 202-25-10, and 202-26-17 continue, both in the near and long term.[11] The production of electricity from the Eddystone Units will continue to be a critical asset for maintaining reliability in PJM. According to data from the U.S. Environmental Protection Agency (EPA), the Eddystone Units generated 26,971 MWh between June 2025 and December 2025,[12] providing vital generation capacity to the region. Over the summer of 2025, PJM took action to manage grid operations, issuing Hot Weather Alerts and/or Maximum Generation Alerts (i.e., an Energy Emergency Alert (EEA) 1) to manage grid reliability covering a total of 20 days, including days in June, July, and August.[13]

PJM's resource adequacy concerns were recently demonstrated during Winter Storm Fern, when PJM operated under a cold weather alert and declared conservative operations from January 24 to February 2, 2026. Additionally, on January 27, 2026, PJM declared a Maximum Generation Emergency/Load Management Alert and an EEA 1.[14]

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[10] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 14.

[11] Further, it likely would be difficult for these units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists. The costs and time of decommissioning a coal plant are extensive and includes various components. Therefore, restarting such decommissioned plants could have significant costs in terms of dollars and time. *See* Section 4 in Lessick, Jennifer, et al. *Business Models for Coal Plant Decommissioning*. www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

[12] *See* EPA, *Custom Data Download, EPA CAMPD (Clean Air Mkts. Program Data)*, https://campd.epa.gov/data/custom-data-download (choose "Emissions" from Data Type dropdown; choose "Monthly Emissions" from Data Subtype dropdown; choose "Unit (No Aggregation)" from Aggregation dropdown; then click "Apply"; then type "2025" into "Time Period" filter and click "June, July, August, September, October, November, December"; then click "Apply Filter"; then click "Facility" filter and type "Eddystone Generating Station (3161)"; then click ""Eddystone Generating Station (3161)"; then click "Apply Filter"; then click "Preview Data").

[13] *See* PJM, *Emergency Procs.*, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (search Effective From 06/01/2025 Effective To 08/31/2025).

[14] *See id.* (search Effective From 01/20/2026 Effective To 02/07/2026).

Due to concerns about resource adequacy from the high demand driven by the extreme cold, PJM also applied for an order pursuant to FPA section 202(c) "that broadly authorizes all electric generating units located within the PJM Region to operate up to their maximum generation output levels, notwithstanding air quality or other permit limitations or fuel shortages during the pendency of this emergency."[15] DOE granted PJM's application and issued Order No. 202-26-02 on January 25, 2026.[16]

On January 29, 2026, PJM applied for an extension of Order No. 202-26-02, which was designated as Order No. 202-26-02A, which was granted by the Department on the same day.[17] Furthermore, on March 17, 2026, in his testimony to the House Committee on Energy and Commerce, North American Electric Reliability Corporation (NERC) Chief Executive Officer Jim Robb stated that "PJM and other grid operators indicated that 202(c) facilities made material contributions" with regard to reliability during Winter Storm Fern.[18]

PJM's resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015.[19] PJM notes that the "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."[20] Further, PJM's risk profile continues to shift from the summer season to the winter season. For example, in a March 2025 presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.[21]

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[15] Letter from Michael E. Bryson, Senior Vice Pres., Operations, PJM, to Hon. Chris Wright, Sec'y, DOE, at 2 (Jan. 4, 2026) (requesting emergency order under FPA section 202(c)), https://www.energy.gov/documents/pjm-202c-application-2026-01-24.

[16] *PJM Interconnection, L.L.C.*, Order No. 202-26-02 (Jan. 25, 2026).

[17] *PJM Interconnection, L.L.C.*, Order No. 202-26-02A (Jan. 29, 2026).

[18] *Winter Storm Fern Lessons: Supplying Reliable Power to Meet Peak Demand; Hearing Before the House Comm. on Energy & Com., Subcomm. On Energy*, 119th Cong. 8 (2026) (statement of James B. Robb, President and CEO, NERC), https://www.congress.gov/119/meeting/house/119077/witnesses/HHRG-119-IF03-Wstate-RobbJ-20260317.pdf.

[19] *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Elec.y Demand*, PJM INSIDE LINES (Jan. 22, 2025), https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/.

[20] *2025 Long-Term Load Forecast Rep. Predicts Significant Increase in Elec. Demand*, PJM INSIDE LINES (Jan. 30, 2025), https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

[21] PJM Res. Adequacy Planning Special Planning Comm., *2026/27 BRA IRM, FPR, & ELCC Class Ratings: Shift Towards More Winter Risk*, at 8 (Mar. 13, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf.

Recognizing the need for and importance of additional generation resources, on April 20, 2026, a Consent Decree between the Commonwealth of Pennsylvania and Keystone-Conemaugh Projects, LLC (KEY-CON) authorized operations to continue at two coal-fired steam electric generating plants that were slated for permanent cessation. The Consent Decree explained that "[d]ue to recent changes in the long-term electricity market outlook based on recent projections by PJM Interconnection LLC and the U.S. Department of Energy, including the need for electricity generators to cover projected increased electrical demand driven by build-out of data centers, particularly within the Mid-Atlantic Area Council, a portion of the PJM Interconnection LLC regional transmission organization that the [Conemaugh Generating Station and Keystone Generating Station] CON has recently reevaluated its 2021 decision to achieve [permanent cessation of coal combustion] at the [Conemaugh Generating Station and Keystone Generating Station] by December 31, 2028."[22]

In the fall of 2025, Pennsylvania Governor Josh Shapiro recognized the need for and importance of securing more electricity generation for the grid. Governor Shapiro stated that "[c]hange is needed to keep energy costs low, bring new energy generation onto the grid more quickly, and meet the needs of the 67 million Americans who rely on this grid for everything from running a business to keeping the lights on at home."[23] Furthermore, PJM expressed support for Order No. 202-25-04, since it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."[24]

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement

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[22] Commonwealth of Pennsylvania, Dep't of Env't Prot. v. Keystone-Conemaugh Projects, LLC, No. 2169-CD-2025-1, slip op. at 4 (Apr. 20, 2026) (Unopposed Motion to Enter Consent Decree), https://www.pa.gov/content/dam/copapwp-pagov/en/governor/documents/motion%20to%20enter%20cd-as%20filed.pdf.

[23] *How Josh Shapiro wants to reshape the region's power grid operator as prices rise*, Spotlight PA (Oct. 14, 2025), https://www.spotlightpa.org/news/2025/10/electricity-prices-shapiro-grid-operator-pjm-data-centers-environment/.

[24] *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30*, PJM INSIDE LINES (May 31, 2025), https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/. Further, PJM concluded, "In light of these concerns, PJM supports the U.S. Department of Energy's Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM's footprint." *Id*.

by 2030.[25] PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately 5%.[26] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[27] PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.[28]

In its December 2024 Reliability Resource Initiative (RRI) filing with FERC, PJM stated that "[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report."[29] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[30] PJM went on to explain that its "resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers" and that its preliminary analysis shows "substantial increases [in load additions] since the 2024 forecast" for both the summer and winter seasons.[31] According to PJM, "load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence."[32] Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.[33]

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM's Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as "extraordinary" and "unprecedented," stating that it "could not have been foreseen as recently as a year ago."[34] Mr. Bielak expressed the opinion that the "rapid" retirement of thermal generation resources, "extreme"

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[25] Four Rs Report, *supra* note 9, at 2.

[26] *Id.*

[27] *Id.* at 16 tbl. 1.

[28] *Id.*

[29] PJM, Filing, , Dkt. No. ER25-712-000, at 10 (Dec. 13, 2024).

[30] *Id.*

[31] *Id.* at 10-11; *see also id.* at 13 (stating that "the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements").

[32] *Id.* at 14.

[33] *See id.* attach. C (Affidavit of Mr. Donald Bielak), at 18–19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, "could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner").

[34] Bielak Aff. at 10.

forecasted load growth, and "delays in new generation resources achieving commercial operation," would adversely affect resource adequacy throughout PJM's electricity grid.[35]

On February 11, 2025, FERC accepted PJM's proposed tariff revisions in its RRI filing.[36] In its order on rehearing, FERC concluded that "PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest."[37]

The NERC has raised similar concerns. In its 2025 Long-Term Reliability Assessment, released in January 2026, NERC observed that the PJM region is at high risk of energy shortfalls over the next five years[38] and faces significant reliability challenges as "[c]urrent projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements."[39] The assessment notes that "[d]emand for electricity in PJM is growing at its fastest pace in years, driven primarily by data centers, followed by electrification and manufacturing loads;" however "[a]t the same time, PJM faces an extreme and rapid tightening of capacity resources in the near term because of generator retirements and project delays."[40] Overall, the assessment concludes that "[b]ased on the load increase and generation decrease, PJM is projecting potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements."[41]

Order Nos. 202-25-04, 202-25-08, 202-25-10, and 202-26-17 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national

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[35] *Id.*at 12.

[36] *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025); *see also, e.g.*, *id.* P 263.

[37] *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).

[38] NERC, *2025 Long-Term Reliability Assessment*, at 7 fig. 1 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[39] *Id.* at 8.

[40] *Id.* at 16.

[41] *Id.* at 91.

security, and foreign policy."[42] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[43] In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[44]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[45] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.[46] As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.[47] In collaboration with the national labs, the Department modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced

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[42] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[43] *Id*.

[44] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[45] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025) [hereinafter Resource Adequacy Report], https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[46] *See* PPL Corporation, *PPL Corporation Q2 2025* Investor *Update*, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf.

[47] *See* Dominion Energy Virginia, *Q4 2024 Earnings Call*, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slides-vTCII.pdf.

coal, gas, and oil generation retirements.[48] Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a maximum unserved load of approximately 21.335 GW.[49]

Grid operators, including PJM, have likewise acknowledged the Nation's current energy crisis. For instance, during a hearing before the United States House of Representatives Committee on Energy and Commerce on March 25, 2025, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."[50] Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from industrial growth."[51] Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.[52] Therefore, Mr. Asthana stated that PJM "encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."[53]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy . . . or other causes," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in his judgment will best meet the emergency and serve the public

[48] Resource Adequacy Report, *supra* note 44, at 28.
[49] *Id.* at 27.
[50] Asthana Test., *supra* note 6, at 4.
[51] *Id.*
[52] *Id.* at 9–10.
[53] *Id.* at 10.

interest."[54] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

As described above, the emergency conditions resulting from the combination of increasing demand and the capacity shortfall stemming from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-04, 202-25-08, 202-25-10, and 202-26-17 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the increased demand for emergency and mitigate the observed shortage of generation, thus serving the public interest pursuant to FPA section 202(c).

To ensure that the Eddystone Units will be available if needed to address emergency conditions, they shall remain available to operate through August 22, 2026.[55]

Based on my determination of an emergency set forth above, I hereby order:

A. From May 25, 2026, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by PJM pursuant to paragraph A. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units have operated in compliance with the allowances contained in this Order.

C. All operations of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with

[54] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

[55] 16 U.S.C. § 824a(c)(4).

the emergency conditions. This Order does not provide relief from any obligation to pay fees, or purchase offsets or allowances for emissions that occur during the emergency conditions, or to use other geographic or temporal flexibilities available to generators.

D. By June 8, 2026, PJM is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

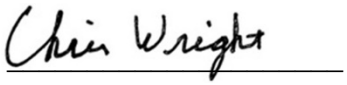
E. Constellation Energy is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal laws or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.

H. This Order shall be effective on May 25, 2026, through August 22, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 21st day of May 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Pennsylvania Public Utility Commission
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit QQQ: Department, Order No. 202-26-28 (June 12, 2026)

Department of Energy
Washington, DC 20585

TransAlta Centralia Generation LLC and
GridForce Energy Management, LLC and
Southwest Power Pool, Inc. Western RC
Regarding the TransAlta Centralia Generation Facility

Order No. 202-26-28

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC)–Northwest assessment area[3] due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

TransAlta Centralia Generation Facility (Centralia) is an electric generating facility in Centralia, Washington. Centralia is owned and operated by TransAlta Centralia Generation LLC (TransAlta). Centralia consists of one remaining coal-fired generation unit, Unit 2, with a nameplate capacity of 729.9 MW.[4] Unit 2 began operations in 1973 and was slated to cease operations in December 2025. Unit 1 was retired in 2020. Unit 2 is slated to cease operation based on a 2011 Washington law[5] and

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] The terms "area" and "region" are used interchangeably herein.
[4] U.S. Energy Info. Admin., *Form EIA-860, Schedule 3: Generator Data (2024)* (Sep. 9, 2025), https://www.eia.gov/electricity/data/eia860m/.
[5] Coal-Fired Elec. Generation Facilities, 2011 Wash. Sess. Laws, Ch. 180, https://lawfilesext.leg.wa.gov/biennium/2011-12/Pdf/Bills/Session%20Laws/Senate/5769-S2.sl.pdf.

a subsequent agreement between TransAlta and the State of Washington.[6] TransAlta has announced plans to convert the unit to natural gas by 2028.[7]

Order Nos. 202-25-11 and 202-25-11B, issued pursuant to FPA section 202(c), required that Centralia remain in operation for 90 days, until March 16, 2026. A subsequent order, Order No. 202-26-18, was issued pursuant to FPA section 202(c), requiring Centralia to remain in operation for 90 days, until June 14, 2026. Those orders were based on my determination that emergency conditions existed in the WECC–Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes.

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[6] *See* Memorandum of Agreement between Christine O. Gregoire, Governor, State of Washington, & Paul Taylor, President, TransAlta Centralia Generation LLC (Dec. 23, 2011), https://ecology.wa.gov/getattachment/858591f6-dd25-47be-ba1d-0f58264ca147/20111223TransAltaMOA.pdf ("D. In exchange for the benefits of entering into an MOA with the State pursuant to RCW 80.80.100, the Company will . . . (5) permanently cease power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives . . . ."); *see also* First Amendment to Memorandum Of Agreement between Jay Inslee, Governor, State of Washington, & Bob Nelson, President, TransAlta Centralia Generation LLC (July 13, 2017), https://fortress.wa.gov/ecy/ezshare/AQ/PDFs/TransAltaMOAAmend1-20170713.pdf. As a coal-fired facility, it likely would be difficult for the Centralia plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if TransAlta were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. The costs and time of decommissioning a coal plant are extensive and includes various components. Therefore, restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. *See* Jennifer Lessick et al., *Bus. Models for Coal Plant Decommissioning* 9–12 (DOE, Pac. Nw. Nat'l Lab'y, Report, Aug. 2021), https://www.pnnl.gov/ main/publications/external/technical_reports/PNNL-31348.pdf; *see also* U.S. Energy Info. Admin., *Capital Cost & Performance Characteristics for Util. Scale Elec. Power Generating Techs.* (Jan. 2024), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

[7] TransAlta, *TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Nat. Gas Conversion* (Dec. 9, 2025), https://transalta.com/newsroom/transalta-signs-long-term-agreement-for-700-mw-at-centralia-facility-enabling-coal-to-natural-gas-conversion/.

Specifically, I determined that the WECC–Northwest region is at an elevated risk of insufficient operating reserves during periods of extreme weather.[8] I determined that the continued operation of Centralia would provide additional generation capacity during these periods, which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.[9] I determined that the continued operation of Centralia was necessary to alleviate immediate and anticipated threats to reliability.[10] My determination was based on a number of facts.

First, in its 2025–2026 Winter Reliability Assessment, the North American Electric Reliability Corporation (NERC) finds that the WECC–Northwest region, which includes Montana, Oregon, Washington, and parts of northern California and northern Idaho, is at elevated risk during periods of extreme weather.[11] The assessment notes that "there is sufficient capacity in the area for expected peak conditions; however, [balancing authorities] are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year [i.e., in 2025–2026 compared to 2024–2025]."[12]

Second, in a September 2025 report evaluating Resource Adequacy in the Pacific Northwest, Energy + Environmental Economics (E3) determined that "[a]ccelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to 9 GW by 2030"[13] and that "[l]oad growth and retirements mean the region faces a power supply shortfall in 2026."[14] E3 reported that nearly 9,000 MW of new capacity will be needed in the region by 2030, but currently only 3,000 MW of projects for new capacity are in active development.[15] Overall, E3 found that "[p]referred resources such as wind, solar and batteries make only small contributions to meeting resource adequacy

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[8] *See, e.g.*, *TransAlta Centralia Generation LLC*, DOE Order No. 202-25-11, at 1 (2025) (*Centralia*).

[9] *See, e.g.*, *id.* at 1–3.

[10] *See, e.g.*, *id.* at 3–4.

[11] NERC, *2025–2026 Winter Reliability Assessment*, at 6 (Nov. 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[12] *Id.*

[13] Wash. Utils. & Transp. Comm'n, *Res. Adequacy & the Energy Transition in the Pac. Nw.: Phase 1 Results*, ENERGY+ENV'T ECON. (E3), at 2 (Sept. 22, 2025), https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20WA%20RA%20Meeting.pdf; *see also id.* (listing E3's study sponsors, which include certain "regional utilities and generation owners").

[14] *Id.* at 10.

[15] *Id.*

needs" and "[t]imely development of all resources is extremely challenging due to permitting and interconnection delays, federal policy headwinds, and cost pressures."[16]

EMERGENCY SITUATION

The emergency conditions that necessitated the issuance of Order Nos. 202-25-11, 202-25-11B, and 202-26-18 continue, both in the near and long term.[17] The production of electricity from Centralia will continue to be an asset to maintain reliability in the WECC Northwest region. According to the U.S. Environmental Protection Agency's data, in 2025,[18] Centralia generated an average of approximately 340,000 MWh per month, providing vital generation capacity to the region.

In its 2025 Long-Term Reliability Assessment,[19] the NERC assessed that the WECC Northwest region is at high risk of energy shortfalls over the next five years,[20] noting that "[r]apid forecasted demand growth is driving the need for more resources" and that "[p]eriods of unserved energy are projected for both summer and winter."[21] The assessment notes that peak load in the region "is forecast to increase by 6.6 GW (19%) over the next 10 years, driven by an influx of data centers into the Pacific Northwest."[22] Additionally, while over 10 GW of new variable resources are in development, the assessment warns that "additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging."[23]

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[16] *Id.* at 2.

[17] *See, e.g.*, Order No. 202-25-11 at 1.

[18] *See* U.S. Env't Prot. Agency, *Custom Data Download, EPA CAMPD (Clean Air Mkts. Program Data)*, https://campd.epa.gov/data/custom-data-download (choose "Emissions" from Data Type dropdown; choose "Monthly Emissions" from Data Subtype dropdown; choose "Unit (No Aggregation)" from Aggregation dropdown; then click "Apply"; then type "2025" into "Time Period" filter and click "January, February, March, April, May, June, July, August, September, October, November, December"; then click "Apply Filter"; then click "Facility" filter and type "Centralia (3845)"; then click "Centralia (3845)"; then click "Apply Filter"; then click "Preview Data").

[19] NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[20] *Id.* at 7.

[21] *Id.* at 8.

[22] *Id.* at 19.

[23] *Id.*

NERC's 2026 Summer Reliability Assessment (2026 SRA) classifies the WECC–Northwest region as an Elevated Risk[24] area with highest-risk conditions occurring in early evening hours (around 6 p.m.) in late summer.[25] The region faces "elevated risks of electricity supply shortfalls during periods of more extreme summer conditions or [is] subject to localized constraints that raise the risk levels of certain small areas within the broader system. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar photovoltaic (PV) energy conditions."[26] Under typical outage conditions the 2026 SRA forecasts reserve margins to be 25.2% and in a scenario with extreme conditions such as higher demand, outages, and derates, reserve margin is estimated to drop to 8.8%, below the 2026 SRA Reference Margin Level of 10.0%. In normal and typical outages, reserve margins in the 2026 SRA are expected to tighten compared to the 2025 SRA, partly due to net demand growth of 4.6% compared to an increase in energy availability by generation resources of 1.5%. NERC notes that "[t]hermal generators with diverse fuel sources can be an important electricity resource, especially during winter when solar PV and battery resources are less capable compared to summer months."[27]

In addition, NERC's 2026 Summer Reliability Assessment notes,

> WECC-Northwest: The coming summer brings challenging hydrological conditions for regions in which hydropower makes up half or more of the supply fleet. Almost the entire Western Interconnection is in the grips of a persistent drought or in an area where drought development has a greater likelihood through the end of July. In Washington, for example, the snow water equivalent was at 52% of normal levels as of April 1 this year when snowpack typically reaches its peak. While the total water year supply is forecast to be nearly average in the Columbia River Basin, snowpack peaked at low elevation and melted early in the year. This has implications for the expected resources available to the Northwest, the generation mix for which is 55% hydropower. The region is contending with a nearly 5% increase in net internal demand from the 2025 SRA and a nearly 2% drop in existing resources as well as a roughly 43% drop in expected Tier 1 resources. Though higher modeled net transfers are projected to contribute double what they were projected to last year (albeit with the increase largely attributable to a modeling change that accounts for economic transfers), this

[24] Elevated risk refers to the potential for insufficient operating reserves in above-normal conditions. NERC, *2026 Summer Reliability Assessment*, at 2–3 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[25] NERC, *2026 Summer Reliability Assessment*, at 2–3 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[26] *Id.* at 2.

[27] *Id.* at 9.

> was not enough to prevent the drop in the Anticipated Reserve Margin from 32% last year to 27% this year.[28]
>
> Peak net internal demand is projected to grow 4.6% over last summer's forecasts; however, anticipated resources are showing just a 1.5% increase in energy availability, leading to tighter margins. Wide-area heat events, wildfires, and low snow-water equivalents due to a changing climate impact generation resource and transmission availability and remain a continued reliability concern. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads or derates, limiting energy availability. Supply chain constraints and economic uncertainty may impact Tier 1 resources. There have been instances where operators had difficulty maintaining frequency due to sudden disconnection of large loads necessitating additional regulation capability. Expected resources do not meet operating reserve requirements under the assessed extreme scenarios.[29]

On March 2, 2026, an amended preliminary injunction was issued by the U.S. District Court for the District of Oregon that imposes operational constraints on the dams that comprise the Federal Columbia River Power System.[30] The restrictions imposed by the amended preliminary injunction will impact power and transmission system reliability, grid stability, and the ability to meet reserve requirements in the WECC–Northwest assessment region.[31] The District Court did not give adequate consideration to the impacts that the preliminary injunction measures will have on the Bonneville Power Administration's (BPA) ability to provide reliable power and transmission services. BPA submitted several declarations detailing the impacts on reliability that would result from the preliminary injunction sought.[32] BPA's modeling of the operational measures in the motion for preliminary injunction concluded that the Columbia River System generation would be greatly decreased in March through November (nine months out of the year) and substantially increase the risk during time periods of high demand such as summer heat waves. [33] Indeed, there is a substantial increased risk that the regional power system will not be able to operate reliably under the ordered spill levels.[34]

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[28] *Id*. at 2.

[29] *Id*. at 36.

[30] *Nat'l Wildlife Fed'n (NWF) v. Nat'l Marine Fisheries Serv. (NMFS)*, No. 3:01-cv-00640 (D. Or. Mar. 2, 2026) (granting amended preliminary injunction).

[31] Fed. Def. Response to Minute Order at 4–5, *NWF v. NMFS*, No. 3:01-cv-00640.

[32] *See, e.g.*, Decl. of Rachel Dibble in Supp. of Fed. Def. Opp'n to Pls. Mot. for a Prelim. Inj., *NWF v. NMFS*, No. 3:01-00640, ECF No. 2574; Decl. of Audrey Stevenson in Supp. of Fed. Def. Opp'n to Pls.' Mot. for a Prelim. Inj., *NWF v. NMFS*, No. 3:01- 00640, ECF No. 2582.

[33] *See* Dibble Decl. ¶ 28; *id.* ¶ 42, fig. 3.

[34] *See, e.g.*, Dibble Decl. ¶ 26; Stevenson Decl. ¶ 18.

Order Nos. 202-25-11, 202-25-11B, and 202-26-18 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[35] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[36] In a subsequent Executive Order No. 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing." [37]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order No. 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[38] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth.

In addition, President Trump issued a White House Memo that emphasized the findings of Executive Order No. 14156 stating that "ensuring reliable coal supply chains and baseload power generation capacity is essential to the United States national defense . . . . Without sufficient coal-fired baseload power, the United States will lack the stable electricity required to support defense installations, industrial expansion, and the high-energy demands of emerging technologies, such as artificial intelligence."[39]

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[35] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[36] *Id.*

[37] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[38] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[39] The White House, *Presidential Determination Pursuant to Sec. 303 of the Defense Product. Act of 1950, as Amended, on Coal Supply Chains & Baseload Power Generation Capacity*, (Apr. 20, 2026), https://www.whitehouse.gov/presidential-actions/2026/04/presidential-determination-pursuant-to-section-303-of-the-defense-

President Trump "further determine[d] that action to expand coal supply chain capacity and baseload generation availability is necessary to avert an industrial resource or critical technology item shortfall that would severely impair national defense capability."[40]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy . . . or other causes," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[41] This statutory language constitutes a specific grant of authority to the Secretary to require the continued availability of Centralia Unit 2 when the Secretary has determined that such continued availability will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

As described above, the emergency conditions resulting from increasing demand and accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes, businesses, and facilities critical to the national defense in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have also made the determination that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Centralia Unit 2 shall be made available for operation through September 12, 2026.

Based on my determination of an emergency set forth above, I hereby order:

A. From June 15, 2025, TransAlta shall take all measures necessary to ensure that Centralia Unit 2 is available to operate at the direction of either Gridforce Energy Management, LLC (in its role as Balancing Authority)[42] or Southwest Power Pool

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production-act-of-1950-as-amended-on-coal-supply-chains-and-baseload-power-generation-capacity.

[40] *Id.*

[41] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

[42] *See* U.S. Energy Info. Admin., *Hourly Elec. Grid Monitor*, EIA-930A 2024 data, https://www.eia.gov/electricity/gridmonitor/about. On EIA-930A 2024 SCH 2, the BA Code for TransAlta Centralia Generation is GRID. *See id.*, EIA-930 data reference tbls., https://www.eia.gov/electricity/gridmonitor/about. On EIA-930 data reference tables, BA Code GRID is associated with Gridforce Energy Management, LLC.

Western RC[43] (in its role as the Reliability Coordinator) or any successors thereto. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices.

B. To minimize adverse environmental impacts, this Order limits operation of Centralia Unit 2 to the times and within the parameters established in paragraph A. TransAlta shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Centralia Unit 2 has operated in compliance with this Order.

[43] *See* Sw. Power Pool, Map (illustrating Regional Transmission Organization and Western Reliability Coordinator footprint with planned expansion), https://www.spp.org/documents/62914/rto%20and%20western%20rc%20footprint%20w%20planned%20expansion.png.

C. All operations of Centralia Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By June 29, 2026, TransAlta is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Centralia Unit 2, consistent with this Order. TransAlta shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

E. TransAlta is directed to file with the Federal Energy Regulatory Commission tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. BPA is directed to facilitate transmission service, as needed, to effectuate this Order.

G. This Order shall not preclude the need for Centralia Unit 2 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Centralia Unit 2 shall not be considered a capacity resource.

I. This Order shall be effective from June 15, 2026, through September 12, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 12th day of June 2026.

Chris Wright

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Washington Utilities and Transportation Commission
Chairman Brian Rybarik
Commissioner Milt Doumit
Commissioner Ann Rendahl

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit RRR: Department, Order No. 202-26-29 (June 18, 2026)

Midcontinent Independent System Operator, Inc. Order No. 202-26-29
Northern Indiana Public Service Company LLC
Regarding R.M. Schahfer Generating Station

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States (U.S.) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The R.M. Schahfer Generating Station (Schahfer) is an electric generating facility in Wheatfield, Indiana. Schahfer is owned and operated by Northern Indiana Public Service Company (NIPSCO), a division of NiSource Inc. Schahfer consists of two 129 MW natural-gas fired generation units and two coal-fired generation units, Unit 17 (423.5 MW) and Unit 18 (423.5 MW).[3] Unit 17 and Unit 18 began operations in 1983 and 1986, respectively. Unit 17 and Unit 18 were both slated to cease operations in December 2025.[4]

Order No. 202-25-12, issued pursuant to FPA section 202(c), required that Schahfer Unit 17 and Unit 18 remain in operation for 90 days, through March 23, 2026. Subsequently, Order No. 202-26-19, issued pursuant to FPA section 202(c), required the Schahfer Units to remain in operation for 90 days, until June 21, 2026. These orders

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] U.S. Energy Info. Admin., *Form EIA-860, Schedule 3: Generator Data* (2024), https://www.eia.gov/electricity/data/eia860/.

[4] It likely would be difficult for the coal-fired units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if NIPSCO were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick et al., *Bus. Models for Coal Plant Decommissioning*, at 9-12 (Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

Specifically, I determined that MISO faced tight reserve margins due to well-documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.[5] I determined that the continued operation of Schahfer would provide additional generation capacity during these periods, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.[6] I determined that the continued operation of Schahfer was necessary to alleviate immediate and anticipated threats to reliability.[7]

My determination was based on several facts. First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area, which covers portions of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, is at an elevated risk, "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[8] Additionally, the LTRA notes that "[t]he departure of MISO's coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years."[9]

Second, MISO's year-round resource adequacy concerns are well-documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[10] MISO justified this revision by explaining that "Reliability risks associated with [r]esource [a]dequacy have shifted from 'Summer only' to a year-round concern."[11]

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[5] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc.*, DOE Order No. 202-25-12, at 1–4 (Dec. 23, 2025).

[6] *See, e.g.*, *id.*

[7] *See, e.g.*, *id.* at 5.

[8] N. Am. Elec. Reliability Corp., *2024 Long-Term Reliability Assessment*, at 13 (Dec. 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

[9] *Id.* at 44.

[10] *Midcontinent Indep. Sys. Operator, Inc.*, Transmittal Letter, FERC Dkt. No. ER22-495-000 (filed Nov. 30, 2021). FERC accepted MISO's proposed tariff revisions on August 31, 2022. *See also Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (2022), *order on reh'g*, 182 FERC ¶ 61,096 (2023).

[11] *MISO*, Transmittal Letter, FERC Dkt. No. ER22-495-000, at 3.

MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[12]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-12 and 202-26-19 continue, both in the near and long term. The production of electricity from Schahfer continues to be critical to maintain reliability in MISO. MISO's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when Schahfer operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 "MaxGen" event for MISO's North and Central Regions due to generation outages, high demand, and transfer capability limits.[13] From January 21–February 1, 2026, Schahfer operated at over 285 MW every day.[14]

In December 2023, MISO released an "Attributes Roadmap," in which it presented an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape.[15] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/2024 Planning Year the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027 there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected risk of loss of load in the winter and spring seasons, which, although not as high as in the summer or fall, will nevertheless increase over time.[16]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, *MISO's Response to the Reliability Imperative.*[17] In a section of that report entitled, *Risks in Non-Summer Seasons,* MISO again stressed that it has resource reliability concerns outside of the summer season.

Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile,

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[12] *Id.* at 3–4.

[13] *See* MISO (@MISO_energy), X (Jan. 24, 2026), https://x.com/MISO_energy/status/201 5072060876140805?s=20.

[14] DOE, *FACT SHEET: Energy Dep't Prevented Blackouts & Saved Am. Lives During Winter Storms* (Feb. 2026), https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms.

[15] MISO, *Attributes Roadmap,* at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[16] *Id.* at 11.

[17] MISO, *MISO's Response to the Reliability Imperative* (updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.

creating risks in non-summer months that rarely posed challenges in the past.[18] These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment, NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years, stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[19] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[20] The 2025 Long-Term Reliability Assessment notes that "MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements."[21] The report observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[22] However, NERC also concluded that "risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high."[23]

According to NERC's 2026 Summer Reliability Assessment, load growth in the MISO region, led by data centers, "is expected to accelerate in 2027 and beyond, which may lead to increased reliability risk in the future if resource additions cannot keep pace with rising load forecasts."[24] It further notes that "[a]bove-normal summer peak load combined with low resource conditions could result in the need to employ operating mitigations (e.g., load-modifying resources) and EEAs [Energy Emergency Alerts]."[25] Since the region benefits from transmission connections with neighbors to meet extreme conditions, MISO's reliance on electricity imports will increase when extreme conditions arise.[26]

The evidence indicates that there is also a potential longer-term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025–26 Planning Year, it noted that "new capacity additions were insufficient to offset

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[18] *Id.* at 12.

[19] NERC, *2025 Long-Term Reliability Assessment*, at 7–8 (Jan. 2026), https://prod.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[20] *Id.* at 43.

[21] *Id.* at 15.

[22] *Id*.

[23] *Id.*

[24] NERC, *2026 Summer Reliability Assessment*, at 16 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[25] *Id.* at 16.

[26] *Id.* at 16.

the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[27]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their annual survey (OMS-MISO Survey), which reported the degree to which expected capacity resources satisfy planning reserve margin requirements.[28] The OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the OMS-MISO Survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin. The OMS-MISO Survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[29] It also projected similar results for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[30]

The primary reasons for these projected deficits also are shown on the OMS-MISO Survey. Large amounts of existing generation capacity are projected to be retired each year, while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[31] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements and does not keep up with the growth in demand.[32]

According to the U.S. Energy Information Administration, coal-fired electricity generation in Indiana has declined from 85% of total generation in 2014 to 42% in 2024. Since 2014, approximately 5,000 MW of coal-fired capacity in Indiana have retired, with nearly another 3,900 MW of coal-fired capacity scheduled for retirement by the end of 2028, which includes Schahfer's capacity.[33]

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[27] MISO, *Planning Res. Auction: Results for Planning Year 2025–26*, at 13 (Apr. 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

[28] OMS and MISO, *OMS-MISO Survey Results* (updated June 6, 2025), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[29] *Id.* at 7.

[30] *Id.* at 9.

[31] *Id.* at 7, 9.

[32] *Id.*

[33] *See* U.S. Energy Info. Admin. , *Indiana Analysis* (Nov. 19, 2025), https://www.eia.gov/states/in/analysis.

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[34] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years after the process begins and are provided an additional three-year grace period to commence commercial operations.[35] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[36] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-12 and 202-26-19 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[37] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[38] In the subsequent Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[39]

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[34] *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[35] *See id.* P 84.

[36] *See generally* S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025) ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

[37] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[38] *Id.*

[39] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

In addition, President Trump issued a White House Memo for the Secretary of Energy that emphasized the findings of Executive Order No. 14156, stating that "ensuring reliable coal supply chains and baseload power generation capacity is essential to the United States national defense . . . Without sufficient coal-fired baseload power, the United States will lack the stable electricity required to support defense installations, industrial expansion, and the high-energy demands of emerging technologies, such as artificial intelligence."[40] The President "further determine[d] that action to expand coal supply chain capacity and baseload generation availability is necessary to avert an industrial resource or critical technology item shortfall that would severely impair national defense capability."[41]

Further, the Department of Energy detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," which was issued pursuant to the President's directive in Executive Order No. 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[42]

Grid operators—including MISO itself—have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[43]

Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected

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[40] Memorandum from President Donald J. Trump to the Secretary of Energy (Apr. 20, 2026) (*Presidential Determination Pursuant to Section 303 of the Defense Production Act of 1950, as Amended, on Coal Supply Chains and Baseload Power Generation Capacity*), https://www.whitehouse.gov/presidential-actions/2026/04/presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-coal-supply-chains-and-baseload-power-generation-capacity/.

[41] *Id.*

[42] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-11/DOE%20Final%20EO%20Report%20%28REVISED%20OCT%2027%29.pdf.

[43] *Keeping the Lights On: Examining the State of Reg' Grid Reliability; Hearing Before the House Comm. on Energy & Com., Subcomm. on Energy*, 119th Cong. 5 (2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Indep. Sys. Operator), https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-CurranJ-20250325.pdf.

demand for energy-hungry data centers to support artificial intelligence."[44] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[45]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[46] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Schahfer Units 17 and 18 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity, or a shortage of electric energy or facilities for generation or transmission of electric energy.

As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Schahfer Units 17 and 18 shall be made available for operation through September 19, 2026.

[44] *Id.* at 6.

[45] *Id.* at 7.

[46] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

Based on my determination of an emergency set forth above, I hereby order:

A. From June 22, 2026, MISO and NIPSCO shall take all measures necessary to ensure that Schahfer Units 17 and 18 are available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Schahfer Units 17 and 18 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. NIPSCO is directed to comply with all orders from MISO related to the availability and dispatch of Schahfer Units 17 and 18.

B. To minimize adverse environmental impacts, this Order limits operation of Schahfer Units 17 and 18 to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Schahfer Units 17 and 18 have operated in compliance with the allowances contained in this Order.

C. All operations of Schahfer Units 17 and 18 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency conditions or to use other geographic or temporal flexibilities available to generators.

D. By July 7, 2026, MISO is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Schahfer Units 17 and 18 consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

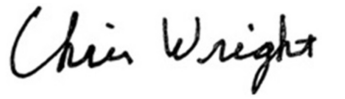
E. NIPSCO is directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Schahfer Units 17 and 18 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Schahfer Units 17 and 18 shall not be considered capacity resources.

H. This Order shall be effective from June 22, 2026, through September 19, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 18th Day of June 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commissioners
Chairman Andy Zay
Commissioner Bob Deig
Commissioner Anthony Swinger
Commissioner David Veleta
Commissioner David Ziegner

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit SSS: Department, Order No. 202-26-30 (June 18, 2026)

Department of Energy
Washington, DC 20585

Midcontinent Independent System Operator, Inc. Order No. 202-26-30
Center Point Energy
Regarding F.B. Culley Generating Station

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States (U.S.) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The F.B. Culley Generating Station ("Culley") is an electric generating facility in Warrick County, Indiana. Culley is owned and operated by CenterPoint Energy and consists of two coal-fired generation units, Unit 2 (103.7 MW) and Unit 3 (265.2 MW), with a combined name plate capacity of 368.9 MW.[3] Unit 2 and Unit 3 began operations in 1966 and 1973, respectively. Unit 2 was slated to cease operations in December 2025.[4]

Order No. 202-25-13, issued pursuant to FPA section 202(c), required that Culley Unit 2 remain in operation for 90 days, through March 23, 2026. Subsequently, Order No. 202-26-20, issued pursuant to FPA section 202(c), required the Culley Unit to remain in operation for 90 days, until June 21, 2026. These orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] U.S. Energy Info. Admin., *Form EIA-860, Schedule 3: Generator Data* (2024), https://www.eia.gov/electricity/data/eia860/.

[4] It likely would be difficult for the coal-fired units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if CenterPoint Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick, et al., *Bus. Models for Coal Plant Decommissioning*, at 9-12 (Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

Specifically, I determined that MISO faced tight reserve margins due to well--documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.[5] I determined that the continued operation of Culley Unit 2 would provide additional generation capacity during these periods, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.[6] I determined that the continued operation of Culley Unit 2 was necessary to alleviate immediate and anticipated threats to reliability.[7]

My determination was based on several facts. First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area, which covers portions of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, is at an elevated risk, "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[8] Additionally, the LTRA notes that "[t]he departure of MISO's coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years."[9]

Second, MISO's year-round resource adequacy concerns are well-documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[10] MISO justified this revision by explaining that "Reliability risks associated with [r]esource [a]dequacy have shifted from 'Summer only' to a year-round concern."[11] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates

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[5] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc*, Order No. 202-25-12, at 1–4 (Dec. 23, 2025).

[6] *See, e.g.*, *id.*

[7] *See, e.g.*, *id.* at 5.

[8] N. Am. Elec Reliability Corp., *2024 Long-Term Reliability Assessment*, at 13 (Dec. 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[9] *Id.* at 44.

[10] *Midcontinent Indep. Sys. Operator, Inc.*, Transmittal Letter, FERC Dkt. No. ER22-495-000 (filed Nov. 30, 2021). FERC accepted MISO's proposed tariff revisions on August 31, 2022. *See also Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (2022), *order on reh'g & compliance*, 182 FERC ¶ 61,096 (2023).

[11] *MISO*, Transmittal Letter, FERC Dkt. No. ER22-495-000, at 3.

emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[12]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-13 and 202-26-20 continue, both in the near and long term. The production of electricity from Culley continues to be critical to maintain reliability in MISO. MISO's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when Culley operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 "MaxGen" event for MISO's North and Central Regions due to generation outages, high demand, and transfer capability limits.[13] From January 21–February 1, 2026, Culley operated at roughly 30 MW almost every day.[14]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape.[15] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/2024 Planning Year the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected risk of loss of load in the winter and spring seasons; which although not as high as in the summer or fall, will nevertheless increase over time.[16]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative.*"[17] In a section of that report entitled, "*Risks in Non-Summer Seasons*," MISO again stressed that it has resource reliability concerns outside of the summer season.

Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile,

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[12] *Id.* at 3–4.

[13] *See* MISO (@MISO_energy), X, (Jan. 24, 2026), https://x.com/MISO_energy/status/2015072060876140805?s=20.

[14] DOE, *FACT SHEET: Energy Dep't Prevented Blackouts & Saved Am. Lives During Winter Storms*, (Feb. 2026), https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms.

[15] MISO, *Attributes Roadmap*, *supra* note 14, at 3.

[16] *Id.* at 11.

[17] MISO, *MISO's Response to the Reliability Imperative* (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.

creating risks in non-summer months that rarely posed challenges in the past.[18] These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment, NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years, stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[19] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[20] The 2025 Long-Term Reliability Assessment notes that "MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements."[21] The report observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[22] However, NERC also concluded that "risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high."[23]

According to NERC's 2026 Summer Reliability Assessment, load growth in the MISO region, led by data centers, "is expected to accelerate in 2027 and beyond, which may lead to increased reliability risk in the future if resource additions cannot keep pace with rising load forecasts."[24] It further notes that "[a]bove-normal summer peak load combined with low resource conditions could result in the need to employ operating mitigations (e.g., load-modifying resources) and EEAs [Energy Emergency Alerts]."[25] Since the region benefits from transmission connections with neighbors to meet extreme conditions, MISO's reliance on electricity imports will increase when extreme conditions arise.[26]

The evidence indicates that there is also a potential longer-term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025–26 Planning Year, it noted that "new capacity additions were insufficient to offset

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[18] *Id.* at 12.

[19] NERC, *2025 Long-Term Reliability Assessment*, at 7–8 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[20] *Id.* at 43.

[21] *Id.* at 15.

[22] *Id*.

[23] *Id.*

[24] NERC, *2026 Summer Reliability Assessment*, at 16 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[25] *Id.* at 16.

[26] *Id.* at 16.

the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[27]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their annual survey (OMS-MISO Survey), which reported the degree to which expected capacity resources satisfy planning reserve margin requirements.[28] The OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the OMS-MISO Survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin. The OMS-MISO Survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[29] It also projected similar results for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[30]

The primary reasons for these projected deficits also are shown on the OMS-MISO Survey. Large amounts of existing generation capacity are projected to be retired each year, while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[31] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements and does not keep up with the growth in demand.[32]

According to the U.S. Energy Information Administration, coal-fired electricity generation in Indiana has declined from 85% of total generation in 2014 to 42% in 2024. Since 2014, approximately 5,000 MW of coal-fired capacity in Indiana have retired, with nearly another 3,900 MW of coal-fired capacity scheduled for retirement by the end of 2028, which includes Culley's capacity.[33]

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to

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[27] MISO, *Planning Res. Auction: Results for Planning Year 2025–26*, at 13 (Apr. 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%20202 50529_Corrections694160.pdf.

[28] OMS and MISO, *OMS-MISO Survey Results* (updated June 6, 2025), https:// cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop %20Presentation702311.pdf.

[29] *Id.* at 7.

[30] *Id.* at 9.

[31] *Id.* at 7, 9.

[32] *Id.*

[33] *See U.S.* Energy Info. Admin., Indiana Analysis (Nov. 19, 2025), https://www. eia.gov/states/in/analysis.

establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[34] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years after the process begins and are provided an additional three-year grace period to commence commercial operations.[35] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[36] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-13 and 202-26-20 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[37] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[38] In the subsequent Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[39]

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[34] *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[35] *See id.* P 84.

[36] *See generally* S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025) ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

[37] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[38] *Id.*

[39] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

In addition, President Trump issued a White House Memo for the Secretary of Energy that emphasized the findings of Executive Order No. 14156, stating that "ensuring reliable coal supply chains and baseload power generation capacity is essential to the United States national defense . . . . Without sufficient coal-fired baseload power, the United States will lack the stable electricity required to support defense installations, industrial expansion, and the high-energy demands of emerging technologies, such as artificial intelligence."[40] The President "further determine[d] that action to expand coal supply chain capacity and baseload generation availability is necessary to avert an industrial resource or critical technology item shortfall that would severely impair national defense capability."[41]

Further, the Department of Energy detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," which was issued pursuant to the President's directive in Executive Order No. 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[42]

Grid operators—including MISO itself—have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025 hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[43]

Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected

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[40] Memorandum from President Donald J. Trump to the Secretary of Energy (Apr. 20, 2026) ("*Presidential Determination Pursuant to Section 303 of the Defense Production Act of 1950, as Amended, on Coal Supply Chains and Baseload Power Generation Capacity*", https://www.whitehouse.gov/presidential-actions/2026/04/presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-coal-supply-chains-and-baseload-power-generation-capacity/.

[41] *Id.*

[42] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[43] *Keeping the Lights On: Examining the State of Reg'l Grid Reliability Before the House Comm. on Energy & Commerce*, Subcomm. on Energy, 119th Cong., at 5 (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Indep. Sys. Operator), https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-CurranJ-20250325.pdf.

demand for energy-hungry data centers to support artificial intelligence."[44] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[45]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[46] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Culley Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity, or a shortage of electric energy or facilities for generation or transmission of electric energy.

As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have determined that, to best meet the emergency arising from increased demand, determined shortage and other causes, and serve the public interest under FPA section 202(c), Culley Unit 2 shall be made available for operation through September 19, 2026.

[44] *Id.* at 6.

[45] *Id.* at 7.

[46] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

Based on my determination of an emergency set forth above, I hereby order:

A. From June 22, 2026, MISO and CenterPoint Energy shall take all measures necessary to ensure that Culley Unit 2 is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Culley Unit 2 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. CenterPoint Energy is directed to comply with all orders from MISO related to the availability and dispatch of Culley Unit 2.

B. To minimize adverse environmental impacts, this Order limits operation of Culley Unit 2 to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Culley Unit 2 has operated in compliance with the allowances contained in this Order.

C. All operations of Culley Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency conditions or to use other geographic or temporal flexibilities available to generators.

D. By July 7, 2026, MISO is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Culley Unit 2 consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

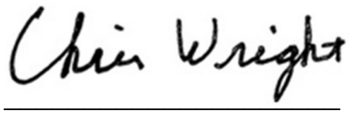
E. CenterPoint Energy is directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Culley Unit 2 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Culley Unit 2 shall not be considered a capacity resource.

H. This Order shall be effective from June 22, 2026, through September 19, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 18th Day of June, 2026.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commissioners
Chairman Andy Zay
Commissioner Bob Deig
Commissioner Anthony Swinger
Commissioner David Veleta
Commissioner David Ziegner

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit TTT: Department, Order No. 202-26-26 (June 4, 2026)

Department of Energy
Washington, DC 20585

Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-26

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists within the SERC Reliability Corporation (SERC)–Florida Peninsula assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The Stanton Energy Center (Stanton) is an electric generating facility in Orlando, Florida. Stanton Unit 1 (464.5 MW)[3] is a coal-fired generator owned[4] and operated by the Orlando Utilities Commission (OUC). Unit 1 began operations in July 1987.[5] The OUC Board of Commissioners had approved the retirement of Unit 1 by 2025,[6] and OUC anticipates placing Stanton Unit 1 in an "extended cold shutdown."[7] OUC expects to

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] U.S. Energy Info. Admin., *Form EIA-860M, Inventory of Operating Generators* (March 2026), (hereinafter EIA, *Form EIA-860M*) https://www.eia.gov/electricity/data/eia860m/. Stanton also includes a second coal-fired generation unit, Unit 2 (464.5 MW) and two natural gas-fired combined cycle generation units, Unit B (129.8 MW) and Unit B1 (203.2 MW).

[4] nFront Consulting LLC, *Orlando Utils. Comm'n 2025 Ten-Year Site Plan*, at 2-3, https://www.floridapsc.com/pscfiles/website-files/pdf/Utilities/Electricgas/TenYearSitePlans/2026/Orlando%20Utilities%20Commission.pdf [hereinafter nFront, *OUC 2025 Ten-Year Site Plan*].

[5] EIA, *Form EIA-860M*, *supra* note 3.

[6] *See, e.g.*, Michelle Lynch, *Fla. Mun. Elec. Ass'n, OUC's Bd. of Comm'rs moves to retire Unit 1 coal plant by no later than 2025* (Dec. 15, 2021), https://www.flpublicpower.com/news/oucs-board-of-commissioners-moves-to-retireunit-1-coal-plant-by-no-later-than-2025.

[7] nFront, *OUC 2025 Ten Year Site Plan*, at 6-2. It likely would be difficult for the coal-fired unit to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if OUC were to begin disassembling the unit or other related facilities, the associated challenges would be

make a determination as to Stanton Unit 2 by year end based on an Integrated Resource Plan currently underway.

EMERGENCY CONDITIONS

In its 2025 Long-Term Reliability Assessment (LTRA), released in January 2026, the North American Electric Reliability Corporation (NERC) notes that the SERC–Florida Peninsula assessment area is currently at a "Normal Risk" for long-term energy adequacy.[8] Nevertheless, the 2025 LTRA highlights that within the SERC–Florida Peninsula assessment area projections for resource and transmission growth lag behind what is needed to support new data centers and other large loads that drive escalating demand forecasts.[9] Additionally, the 2025 LTRA maintains that new data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years.[10] As of April 2026, eight data centers are planned for construction in Florida.[11] Total peak demand is expected to increase from 48,628 MW in 2025/2026 to 54,931 MW in 2034/2035.[12]

The 2025 LTRA also notes that, with "the heavy dependence on natural gas in the SERC–Florida Peninsula subregion, fuel diversity could become an area of future concern."[13] Further, the 2025 LTRA states that:

> [t]he growing penetration of renewable energy means that SERC and the SERC–Florida Peninsula entities will need to continue to monitor the resource adequacy studies and the impact that renewable resources will have. As solar generation

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greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick et al., *Business Models for Coal Plant Decommissioning*, at 9–12 (Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

[8] N. Am. Elec. Reliability Corp., *2025 Long-Term Reliability Assessment*, at 23 (Jan. 2026), https://prod.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf [hereinafter NERC, *2025 LTRA*].

[9] *Id.* at 6.

[10] *Id.* at 9.

[11] *See* Skyler Seets & Kaitlyn Radde, *Most new data centers in the U.S. are coming to rural areas*, PEW RESEARCH CENTER (Apr. 13, 2026), https://www.pewresearch.org/?p=299017.

[12] *See* Fla. Reliability Coordinating Council, Inc., *2025 Reg'l Load & Res. Plan FRCC-MS-PL-642 Version: 1*, at 6 (2025), https://www.floridapsc.com/pscfiles/website-files/PDF/Utilities/Electricgas/TenYearSitePlans//2025/FRCC_RLRP.pdf.

[13] *See* NERC, *LTRA*, *supra* note 9, at 116.

continues to grow, the need to ensure the availability of quick start generating units to meet the ramp in demand will increase.[14]

OUC resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when OUC requested two section 202(c) emergency orders to preserve the reliability of the bulk electric power system due to anticipated unusually high load forecasts from unusual cold weather conditions throughout the entire state of Florida: (i) one application[15] for 2.7 GW of specified resources (generating units) [16] and (ii) another[17] for 55 MW of back-up generators.[18] As a result, DOE issued two 202(c) emergency orders to OUC from January 31 through February 6: (i) Order No. 202-26-11 for specified resources,[19] and (ii) Order No. 202-26-15 for back-up generators.[20] OUC leveraged the 202(c) orders to meet demand during extreme cold weather conditions. Stanton Unit 1 produced 66,230 MWh between January 31, 2026 and February 6, 2026.[21] The back-up generating units reported over 400 hours of run-time under the respective Order.

According to OUC, customer demand was projected to exceed record-breaking thresholds for OUC on Sunday, February 1, 2026, and again on Monday, February 2, 2026, and maybe throughout the following week.[22] OUC had projected that it may not have sufficient generation available to meet the unusually high demand and may be forced to curtail load in order to maintain the security and reliability of the grid.[23] In January 2026, Stanton Units 1 and 2 produced a total of 249,473 MWh from coal-fired generation.[24]

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[14] *Id.*

[15] OUC 202(c) Application (Jan. 31, 2026).

[16] OUC Specified Resources (Exhibit A to 202(c) Application) (Jan. 31, 2026).

[17] OUC 202(c) Application – Backup Generators (Jan. 31, 2026).

[18] OUC 202(c) Application Exhibit A – Backup Generators (Jan. 31, 2026).

[19] *Orlando Utils. Comm'n*, Order No. 202-26-11 (Jan. 31, 2026).

[20] *Orlando Utils. Comm'n*, Order No. 202-26-15 (Jan. 31, 2026).

[21] *See* U.S. Env't Prot. Agency, CAMPD (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (choose "Emissions" from "Data Type" dropdown; then choose "Daily Emissions" from "Data Subtype" dropdown; then choose "Unit (No Aggregation)" from the "Aggregation" dropdown; then click "Apply"; then click "Time Period" button and enter "January 31, 2026" as "Start Date" and February 6, 2026 as "End Date"; then click "Facility" and select "Curtis H. Stanton Energy Center"; then click "Apply Filter"; then click "Preview Data".).

[22] Letter from Clint Bullock, Gen. Manager & CEO, Orlando Utils. Comm'n, to The Honorable Chris Wright, Sec'y, Dept. of Energy (Jan. 31, 2026) (requesting emergency order under FPA section 202(c)), https://www.energy.gov/documents/ouc-202c-application-backup-generators.

[23] *Id.*

[24] EIA, *Form EIA-923, Schedule 4: Generator Data* (Apr. 2026), https://www.eia.gov/electricity/data/eia923/.

According to NERC's 2026 Summer Reliability Assessment, the SERC–Florida Peninsula is a summer-peaking assessment area.[25] It further notes that "[t]emperature and precipitation forecasts for the coming summer show a higher likelihood of hotter-than-normal temperatures in the U.S. South . . . ."[26] For the SERC–Florida Peninsula, the anticipated reserve margin is projected to be 25.8%; however, the anticipated reserve margin drops to 13.6% in the event of "higher demand, outages, [or] derates in extreme conditions."[27]

Executive orders issued by President Donald J. Trump on January 20, 2025, and April 8, 2025, underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[28] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets." In the subsequent Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[29]

Further, the Department of Energy detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," which was issued pursuant to the President's directive in Executive Order No. 14262. The Department concluded that, "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[30]

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[25] North American Electric Reliability Corporation, 2026 Summer Reliability Assessment, at 28 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[26] *Id.* at 4.

[27] *Id* at 10.

[28] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[29] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[30] DOE, RES. ADEQUACY REP.: EVALUATING THE RELIABILITY & SEC. OF THE U.S. ELEC. GRID (Jul. 7, 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[31] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Stanton Unit 1, when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity, or a shortage of electric energy or facilities for generation or transmission of electric energy.

As described above, the conditions resulting from the combination of increasing demand and shortage will continue on in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or power outages, presenting a risk to public health, and safety.

I have determined that, under the conditions specified below, continued availability of Stanton Unit 1 is necessary to best meet the emergency arising from increased demand for electric energy, shortage of facilities for the generation of electric energy, and other causes, thus serving the public interest pursuant to FPA section 202(c).

To ensure that Stanton Unit 1 will be available if needed to address emergency conditions, it shall remain in operation through September 1, 2026.

[31] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

Based on my determination of an emergency set forth above, I hereby order:

A. From June 4, 2026, OUC shall take all measures necessary to ensure that Stanton Unit 1 is not placed in extended cold shutdown and is available to operate.[32] Following the conclusion of this Order, sufficient time for orderly ramp down will be permitted, consistent with industry practices.

B. To minimize adverse environmental impacts, this Order limits operation of Stanton Unit 1 to the times and within the parameters as determined by OUC pursuant to paragraph A. OUC shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Stanton Unit 1 has operated in compliance with the allowances contained in this Order.

C. All operations of Stanton Unit 1 must comply with applicable environmental requirements, including, but not limited to, monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency conditions or to use other geographic or temporal flexibilities available to generators.

D. By June 18, 2026, OUC is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Stanton Unit 1, consistent with this Order. OUC shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

E. OUC is directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Stanton Unit 1 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Stanton Unit 1 shall not be considered a capacity resource.

[32] According to OUC, neither Florida Municipal Power Pool (FMPP) in its role as the Balancing Authority nor Florida Reliability Coordinating Council (FRCC) in its role as the Reliability Coordinator directs OUC to operate Stanton 1 in a manner similar to organized markets.

H. This Order shall be effective from June 4, 2026, through September 1, 2026, with the exception of applicable compliance obligations in paragraph D.

I. OUC is directed to provide the Department at least fifteen days' prior advance notice in writing before any change in operational status or otherwise of Stanton Unit 2 occurs.

Issued in Washington, D.C. on this 4th day of June 2026.

Chris Wright

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Florida Public Service Commissioners
Chairman Gabriella Passidomo Smith
Commissioner Gary F. Clark
Commissioner Mike La Rosa
Commissioner Bobby Payne
Commissioner Ana Ortega

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit UUU: WECC, Summer 2026 Assessment Overview

Summer Reliability Assessment Western Overview 2026



The Summer Reliability Assessment (SRA) covers the upcoming summer season, providing an evaluation of reliability for projected risk periods while identifying potential reliability issues of interest and regional topics of concern. Among the findings:

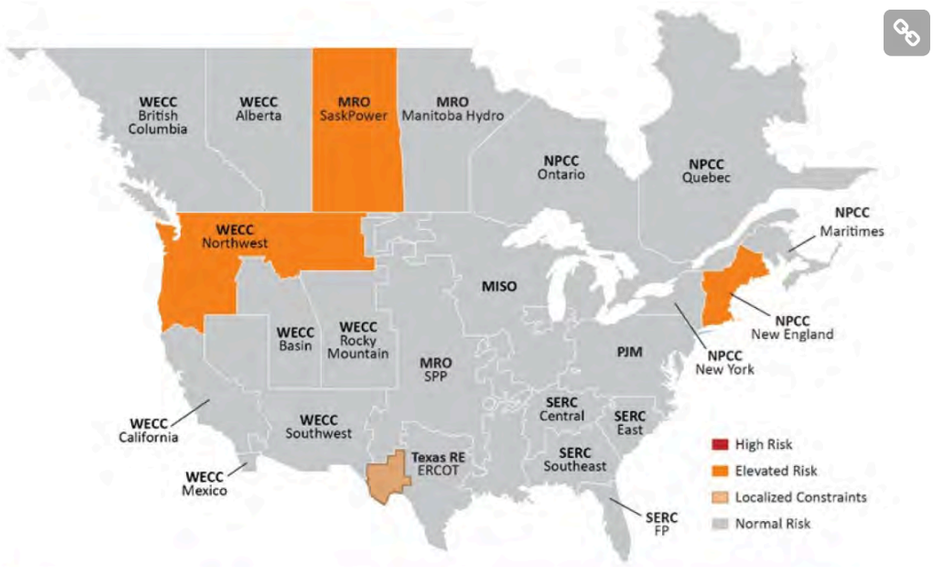
- Continent-wide, the 2026 summer risk profile is characterized by rising demand, significant resource additions in many areas, the prospect of challenging hydrological conditions, and unpredictability associated with large loads.
- All areas have adequate anticipated resources for normal summer peak load conditions, according to the assessment; however, three areas face elevated risk of supply shortfalls during periods of more extreme summer conditions, including the Western Interconnection's Northwest subregion.
- An influx of resources, primarily solar and battery but also natural gas-fired generation, has outpaced demand and boosted reserves, easing resource adequacy concerns across the continent.
- Large loads pose operational challenges for the summer. Recent events in which large loads unexpectedly disconnected from the grid in the Eastern Interconnection and ERCOT highlight the need for operational readiness this summer and illustrate why NERC is closely examining the potential risks posed by large loads.
- The overlap of early summer heat and spring maintenance outages can lead to reliability risks.

NERC Summer Reliability Assessment: Western Overview

Each year, WECC partners with the North American Electric Reliability Corporation (NERC) and the rest of the Electric Reliability Organization (ERO) Enterprise to develop the NERC SRA. This assessment evaluates system resource adequacy and reliability across North America for the upcoming summer season. Below are highlights from the assessment specific to the Western Interconnection.

Key Takeaways

- Common reliability concerns across the Western Interconnection for summer 2026 are threats from wildfire, resource adequacy in periods of extreme heat, and drought, which exacerbates the wildfire threat and can lead to diminished hydro output. These concerns vary in severity in each of the eight WECC subregions.
- Wide-area heat events or wildfires that affect resource and transmission availability across the Western Interconnection are a concern. The ability to import energy may be limited during these events.
- Supply chain constraints and economic uncertainty may affect planned resources across the interconnection.
- Along with challenging hydro conditions, the Northwest's elevated designation centers on a nearly 5% increase in demand projected for this summer from the 2025 SRA, a nearly 2% decrease in existing resources, and a significant drop in planned resources.



Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected







Subregion Reliability Highlights

British Columbia: Peak demand is projected to increase 2.4% over last summer's forecasts, while anticipated resources increase by almost 16%. In WECC's analysis, no loss of load emerged in a range of conditions.

Alberta: Peak demand is projected to increase 2.1% over last year's forecasts, while anticipated reserve margins exceed the prescribed margin level. In WECC's analysis, no loss of load emerged in a range of conditions.

Northwest: Peak demand is projected to grow 4.6% over last summer's forecasts, while anticipated resources show a 1.5% increase in energy availability, leading to tighter margins. Supply chain constraints and

economic uncertainty may affect planned resource additions. The elevated risk of shortfalls in the assessment occurs in August and September.



California: Extreme heat and wildfires may affect generation and transmission resources and remain a reliability concern. Variability of inverter-based resources is a concern, particularly in the evening when solar generation wanes and wind generation can be curtailed due to Santa Ana Winds.



Mexico: The subregion added 1 GW of gas-fired generation since last summer, significantly improving the outlook from the 2025 SRA. Operating reserves are a concern during periods of extreme heat and elevated demand, however. Anticipated reserves are projected to be 16% higher, but some generating units have reached advanced operational age, resulting in an increase in the forced outage rate. This raises the risk of capacity shortfalls, potentially compromising system reliability during peak summer demand.



Basin: Peak demand is projected to increase by 4%, due in part to a significant decrease in demand response availability, while anticipated resource capacity is expected to increase by 16% from last summer's forecasts.



Rocky Mountain: Peak demand is projected to decline by 3%, while anticipated resource capacity is expected to increase by 15%. Climate change and ecological factors are raising the wildfire risk in the subregion, although the entities have engaged in substantial mitigation efforts.

Southwest: Peak demand is projected to increase by 10% over last summer's forecasts, while anticipated resource capacity is expected to increase by 33% since last summer's forecasts. The subregion faces grid reliability concerns posed by large loads if new generation resources are delayed as new load comes online.


MEXICO


BASIN


BASIN

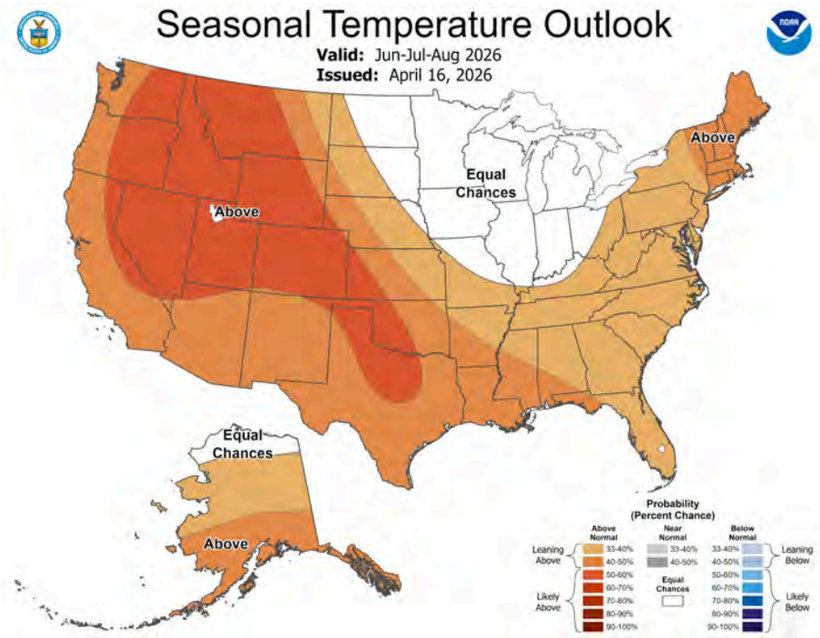

ROCKY
MOUNTAIN

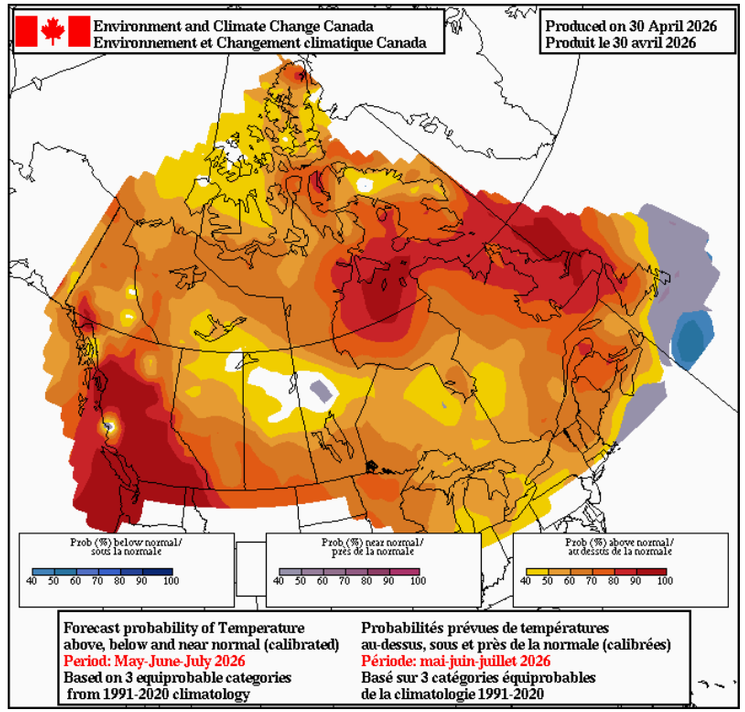

ROCKY
MOUNTAIN


SOUTHWEST

Summer Conditions and Drought Affecting the Bulk Power System

Forecasts indicate above-normal temperatures for much of the West this summer as an El Nino weather pattern is expected. Drier-than-normal conditions are expected in the Northwest, where the snowpack is below average. In Canada, higher-than-normal temperatures are expected in the northeast. Snowpack in Canada is generally in average condition, with a pocket of below-average snowpack in southwest British Columbia. To learn more about the expected summer weather and operating conditions, view the *Reliability in the West Discussion Series: Assessing Summer Conditions and Readiness*.





Extreme Heat



The summer peak declined in the Western Interconnection in 2025, to 163 GW from 168 GW in 2024, as most of the West saw a moderation in heat compared to 2024. And, while the interconnection experienced relatively few emergency events, there were heat events that stressed the system.

- A heat wave in western Canada from late August through early September broke records in British Columbia and exacerbated drought conditions. Parts of western Canada saw generation outages that triggered energy emergency alerts (EEA).
- In Mexico, generation losses in late August triggered EEAs.
- In the Rocky Mountain subregion, Utah and Nevada recorded their warmest years on record.

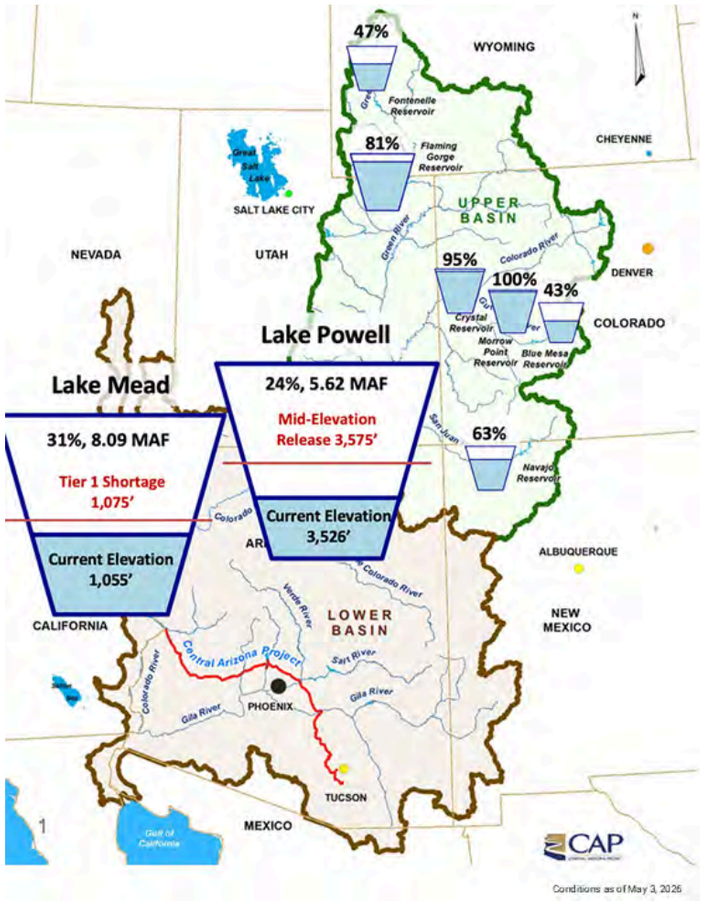
Challenging Hydro Conditions

Drought conditions are either in place or are likely to develop this summer throughout much of the interconnection. This could affect hydropower generation (hydro has the second-most nameplate capacity installed in the Western Interconnection).

In the Northwest subregion, where hydro makes up more than half of the resource mix, the snow water equivalent was at 52% of normal as of April 1. While the water year is forecast to be about average in the Columbia River Basin, snowpack melted earlier in the year. This has implications for the expected resources available in the Northwest.

The Southwest subregion is less reliant on hydro, but one significant hydro facility on the Colorado River System, the 1 GW Glen Canyon Dam at Lake Powell, had been projected to be unable to generate power due to low water levels as soon as August 2026. The Bureau of Reclamation has taken steps to prevent this, announcing plans in late April to release enough water from the Flaming Gorge Reservoir to increase Lake Powell's elevation to sufficient levels for power generation.

Downriver, Hoover Dam is operating in shortage conditions, but the most recent projections indicate Lake Mead will maintain levels needed to generate power at the 2 GW facility throughout the 24-month period studied.



WECC

The Independent Voice of Bulk Power System Reliability in the Western Interconnection

TOP

Built with **Shorthand**

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit VVV: WECC, 2025 Western Assessment Supplemental Information

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WECC



2025 Western Assessment Supplemental Information

Introduction

WECC's annual Western Assessment of Resource Adequacy provides a high-level examination of resource-adequacy-related risks to the reliability of the Western Interconnection over the next 10 years. Through an energy-based probabilistic approach, WECC examines the risks across the entire interconnection and eight subregions. This work is intended to help stakeholders target specific areas and topics for deeper evaluation and mitigation. The 10-year assessment period for this year's Western Assessment is 2026 through 2035.

This supplemental material provides a more in-depth look at the eight subregions that make up the Western Interconnection, with information on resource portfolio, demand projections, planned resource additions and retirements, and how the subregion fared in WECC's analysis. All times listed are Pacific Time.

Scenarios

WECC performed six scenarios in the 2025 Western Assessment, using data provided by WECC members as of the end of 2024. This information included planned resource additions and retirements over the coming decade, as well as demand forecasts for the 10-year assessment period.

The “All Additions” scenario evaluated resource adequacy assuming all planned resource additions and retirements come to fruition, while three scenarios reduced the planned resource additions. Resource additions in these scenarios were based on capacity decreases of 5%, 15%, and 33%, respectively. These scenarios are called the “95% Additions,” “85% Additions,” and the “67% Additions” scenarios. The reduction in resource additions was applied evenly to each resource type and subregion. Demand forecasts in these scenarios were unaltered for the assessment period and reflect annual and peak demand projections as of year-end 2024.

The remaining two scenarios focused on demand in the years 2030 and 2035. The “High Load Scenario" incorporates large load customer demand that was not included in original demand forecasts due to uncertainty in customer materialization. The additional demand from these customers is modeled as being present 24/7, year-round. Resource additions were not altered in the High Load scenario.

Incremental Large Load Demand Added to Peak Demand Forecast (MW)		
Region	2030	2035
Alberta	1,520	1,995
California	-	100
Northwest	3,137	3,513
Rocky Mountain	597	723
Southwest	3,085	3,798
Total	**8,340**	**10,130**

Incremental Net Energy Added to Load Forecast (GWH)		
Region	2030	2035
Alberta	13,315	17,476
California	-	876
Northwest	27,484	30,774
Rocky Mountain	5,231	6,336
Southwest	27,028	33,273
Total	**73,058**	**88,736**

Large load demand added to the peak and annual demand forecasts in the High Load Scenario.

The “Low Load Scenario" applies percentage reductions to peak and annual demand forecasts in 2030 and 2035. The reductions are seasonal for the peak hour forecasts and applied evenly to the annual demand forecasts. The shoulder season reductions for the peak hour are an average of the summer and winter percentage reductions. The percentages chosen represent an approximation of the typical high-side forecasting error for peak and annual demand. They are shown below. Resource additions were not altered in the Low Load Scenario:

Summer Peak		Winter Peak		Annual Demand	
2030	2035	2030	2035	2030	2035
-2.5%	-5.0%	-5.0%	-10%	-5.0%	-10%

Reductions to peak and annual demand forecasts in the Low Load Scenario

Results

Resource adequacy metrics, such as loss of load events (LOLEv), loss of load hours (LOLH), expected unserved energy (EUE), and duration of loss of load events, were derived for each scenario by subregion and are provided below for years 2030 and 2035.

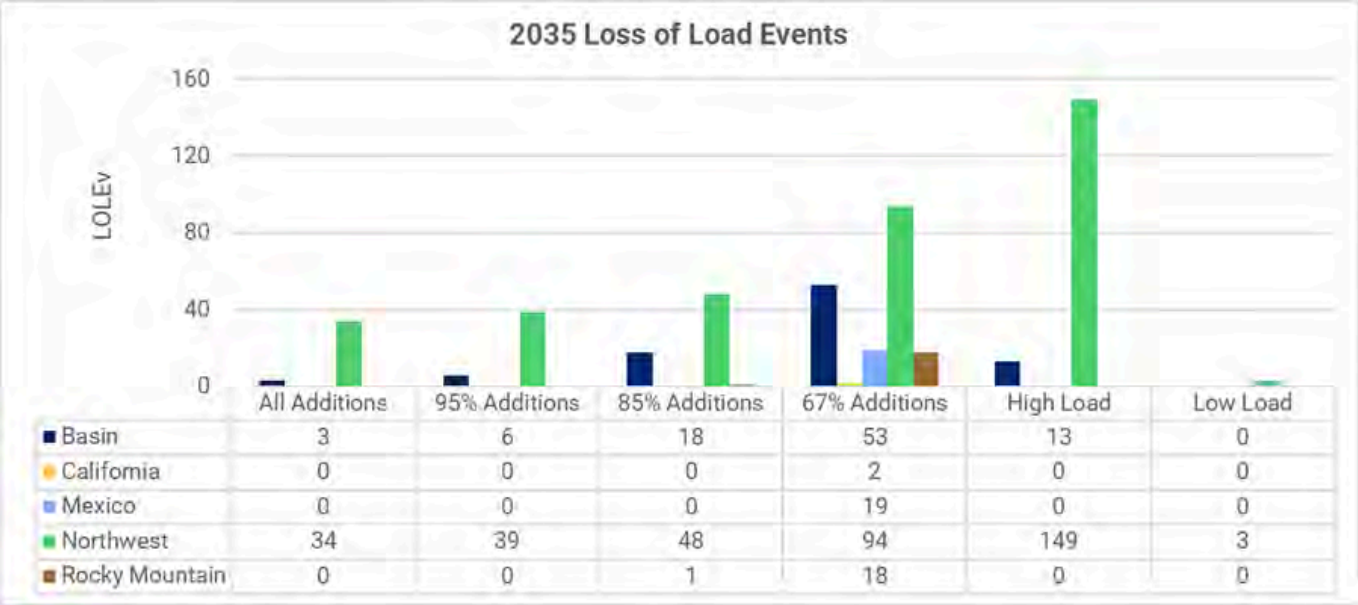
Loss of Load Events



	All Additions	95% Additions	85% Additions	67% Additions	High Load	Low Load
Basin	0	2	9	30	5	0
Northwest	8	8	12	19	46	1
Rocky Mountain	0	0	0	1	0	0

LOLEvs by subregion and scenario for 2030

An LOLEv is a period during which system load cannot be served. The Northwest contains the greatest LOLEvs across all scenarios. Both Basin and the Northwest encounter LOLEvs as early as 2029 in the All Additions Scenario, however only the Northwest shows LOLEvs in 2030. When 3 GW of speculative large load demand is added to the Northwest subregion in the High Load Scenario, the Northwest's LOLEvs increase dramatically. It should also be noted that when demand is reduced in the Low Load Scenario, there is a singular LOLEv for the Northwest in 2030. This is noteworthy as the Low Load Scenario incorporates all planned resource additions. The Rocky Mountain subregion has one LOLEv in 2030 in the 67% Additions Scenario.



	All Additions	95% Additions	85% Additions	67% Additions	High Load	Low Load
Basin	3	6	18	53	13	0
California	0	0	0	2	0	0
Mexico	0	0	0	19	0	0
Northwest	34	39	48	94	149	3
Rocky Mountain	0	0	1	18	0	0

LOLEvs by subregion and scenario for 2035

Examining the 2035 LOLEvs, California and Mexico show loss of load in the 67% Additions Scenario. California has one LOLEv in 2032 and 2033, and two LOLEvs in 2035. Mexico has one LOLEv in 2034 and 19 LOLEvs in 2035. The Rocky Mountain subregion shows 18 LOLEvs in 2035 in the 67% Additions Scenario and shows an LOLEv in 2034 and 2035 in the 85% Additions Scenario. The Northwest shows LOLEvs across all scenarios in 2035, with the greatest amount shown in the High Load Scenario. The High Load Scenario features over 3.5 GW of additional consumer demand for the Northwest subregion in 2035, driving this increase. The Northwest is also the only subregion showing LOLEvs in 2035 for the Low Load Scenario. Basin shows LOLEvs in all scenarios except the Low Load Scenario.

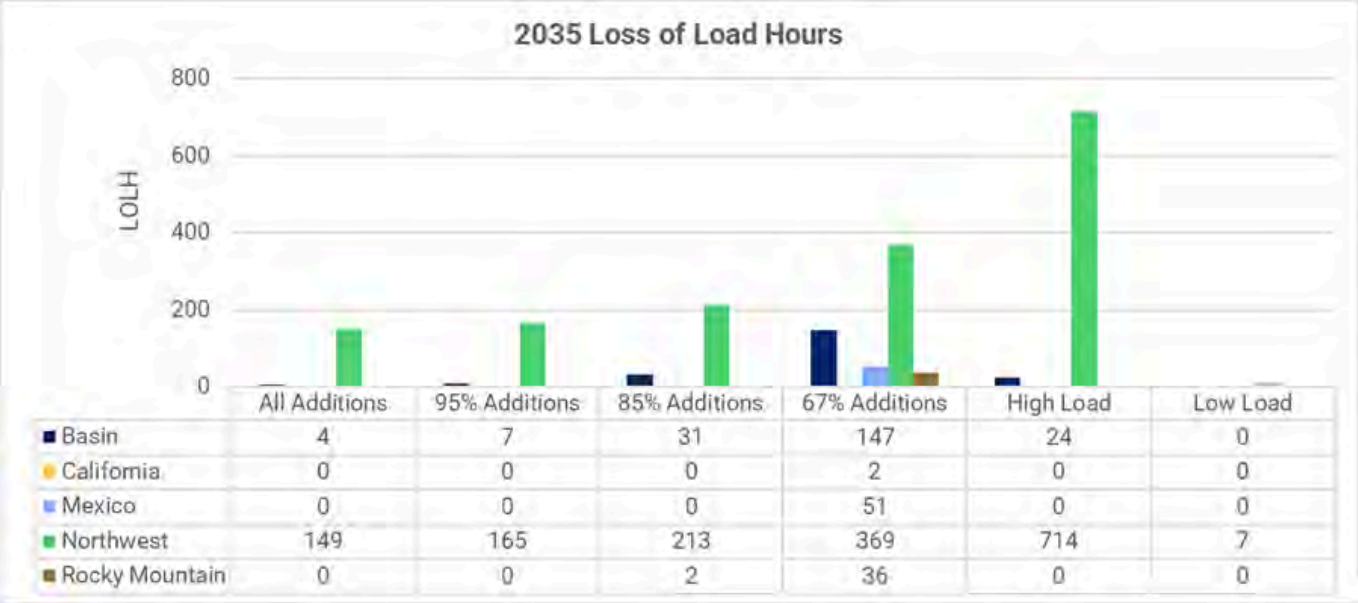
Loss of Load Hours



	All Additions	95% Additions	85% Additions	67% Additions	High Load	Low Load
Basin	0	2	14	68	7	0
Northwest	17	19	35	70	218	1
Rocky Mountain	0	0	0	1	0	0

LOLHs by subregion and scenario for 2030

LOLHs are the number of hours a subregion's demand is projected to exceed generating capability. LOLHs for each scenario in 2030 are provided above. Results viewed through the lens of LOLHs are generally similar to those of LOLEvs, in that the Northwest and Basin subregions show most of the LOLHs. It is noteworthy in the 2030 67% Additions Scenario that Basin displayed more LOLEvs; however, the Northwest subregion shows greater LOLHs. This indicates the Northwest is generally experiencing longer LOLEvs. In the 2030 67% Additions Scenario, the average length of time per LOLEv in the Northwest is close to four hours, whereas, for Basin, LOLEvs average about two hours. The Northwest shows over 200 LOLHs in the High Load Scenario with 46 LOLEvs, increasing the average length of LOLEv to almost five hours. Rocky Mountain has one LOLH in 2030 in the 67% Additions Scenario.

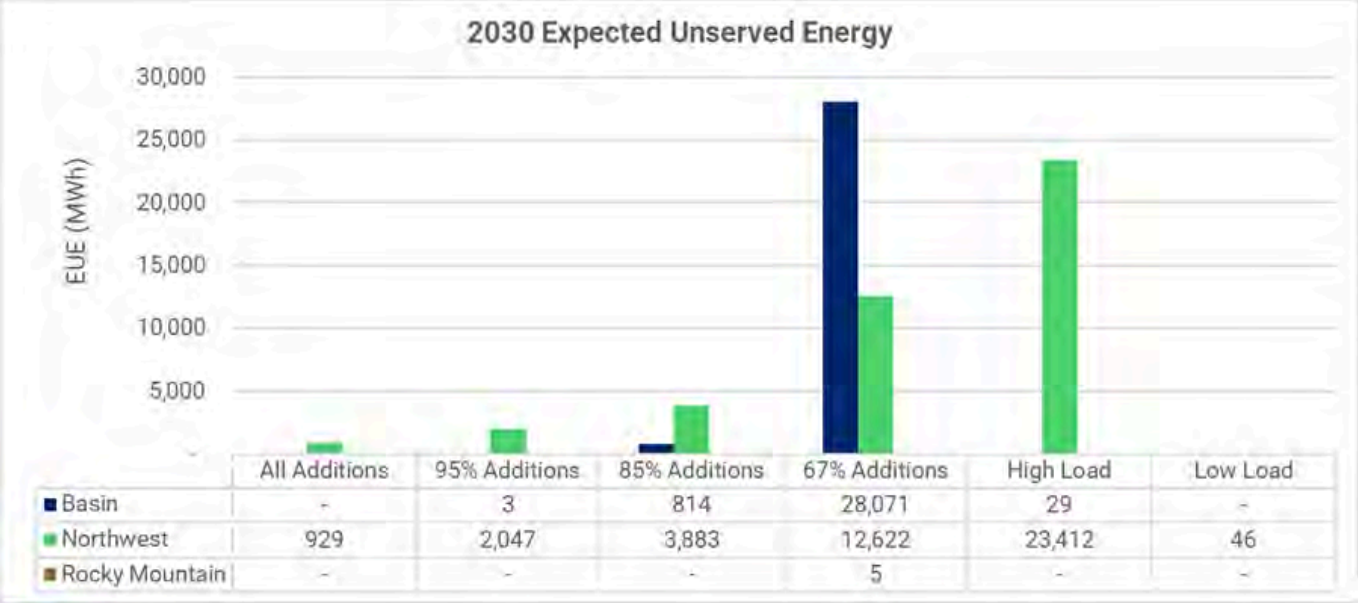


	All Additions	95% Additions	85% Additions	67% Additions	High Load	Low Load
Basin	4	7	31	147	24	0
California	0	0	0	2	0	0
Mexico	0	0	0	51	0	0
Northwest	149	165	213	369	714	7
Rocky Mountain	0	0	2	36	0	0

LOLHs by subregion and scenario for 2035

Comparing 2035 to 2030, LOLHs increase across the board in all scenarios. Basin and the Northwest show LOLHs in the All Additions Scenario, whereas Rocky Mountain has LOLHs in the 85% Additions Scenario. The Northwest shows over 700 LOLHs in the High Load Scenario, and similar to the 2030 High Load Scenario, averages approximately five hours per LOLEv. The Northwest also shows seven LOLHs in the Low Load Scenario. Basin shows 147 LOLHs in the 67% Additions Scenario spread over 53 LOLEvs, averaging about three LOLHs per LOLEv. California shows two LOLHs in the 2035 67% Additions Scenario, whereas Mexico shows 51 LOLHs. The 51 LOLHs for Mexico were spread over 19 LOLEvs, resulting in an average duration of about three hours per LOLEv.

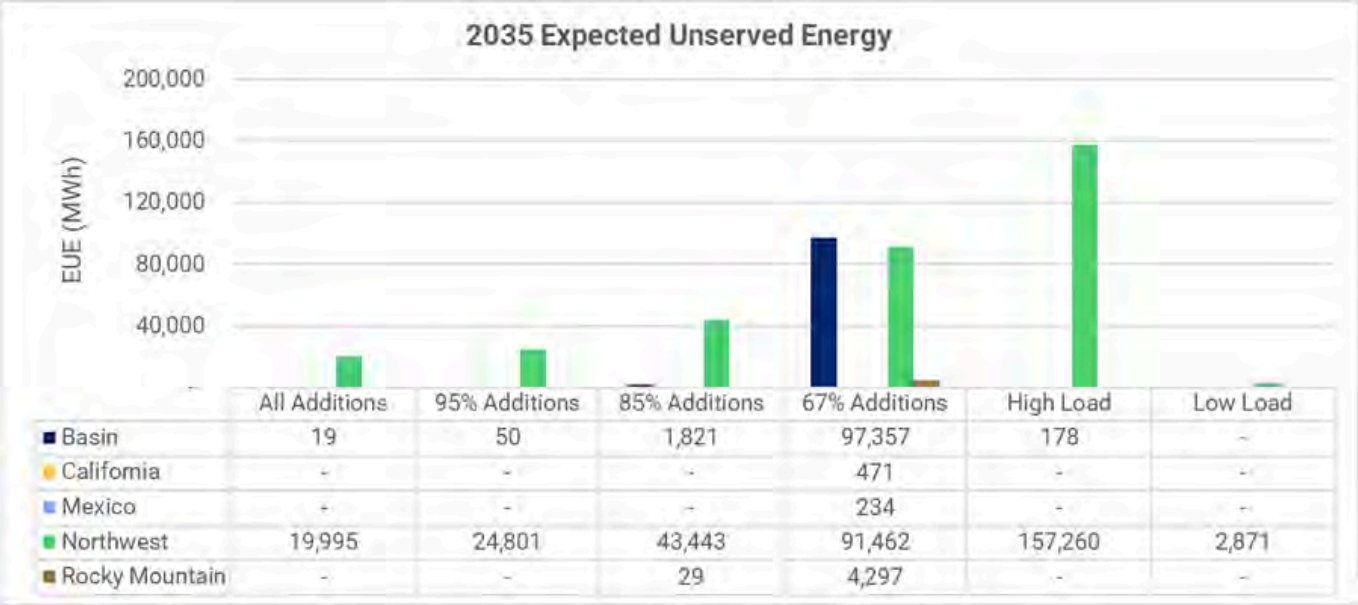
Expected Unserved Energy



	All Additions	95% Additions	85% Additions	67% Additions	High Load	Low Load
Basin	-	3	814	28,071	29	-
Northwest	929	2,047	3,883	12,622	23,412	46
Rocky Mountain	-	-	-	5	-	-

EUE by subregion and scenario for 2030

EUE is the anticipated demand that will not be served due to demand exceeding available energy. It is intended to provide a measure of energy shortfall. In the 67% Additions Scenario, Basin and the Northwest have nearly identical LOLHs; however, Basin's EUE was 28.1 GWh versus the Northwest's 12.6 GWh. Basin's hourly average EUE in the 2030 67% Additions Scenario is slightly over 410 MWh, whereas the Northwest's hourly average EUE in this scenario is closer to 180 MWh. As such, despite the Northwest having more frequent and longer LOLEvs, the magnitude of energy shortfall in those events is typically shallower than the LOLEvs in Basin. This trend reverses in the High Load Scenario in which Basin shows 29 MWh of EUE over seven LOLHs, whereas the Northwest shows 23.4 GWh of EUE over 218 LOLHs.

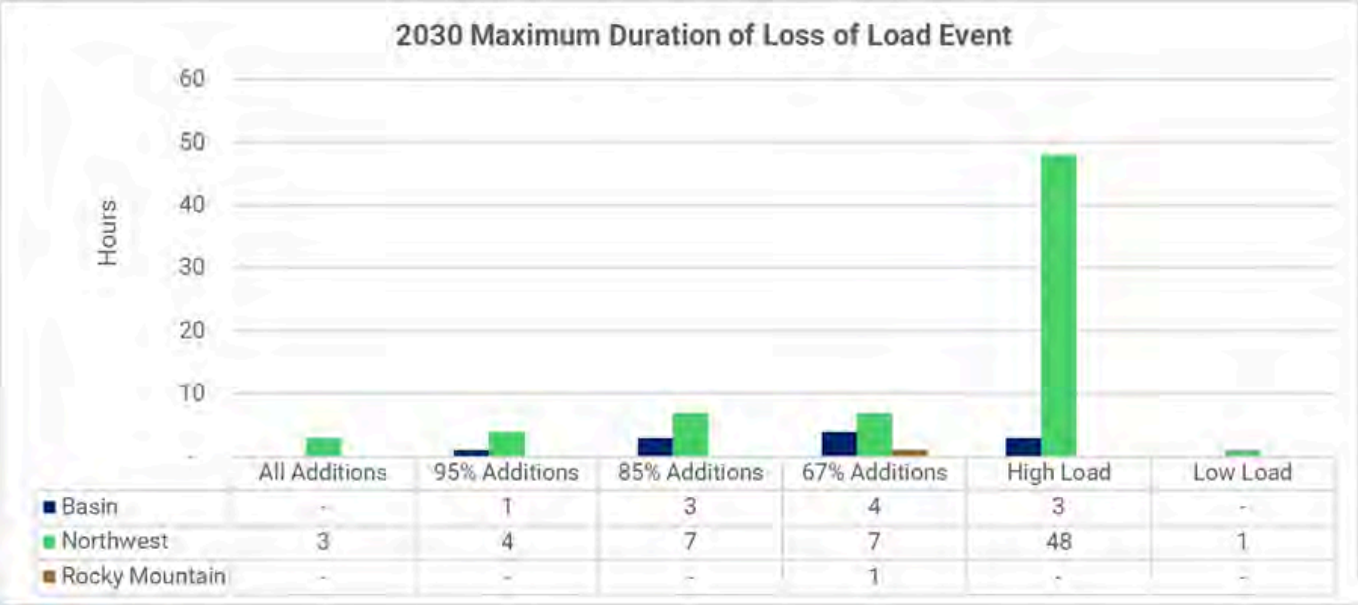


	All Additions	95% Additions	85% Additions	67% Additions	High Load	Low Load
Basin	19	50	1,821	97,357	178	-
California	-	-	-	471	-	-
Mexico	-	-	-	234	-	-
Northwest	19,995	24,801	43,443	91,462	157,260	2,871
Rocky Mountain	-	-	29	4,297	-	-

EUE by subregion and scenario for 2035

The 2035 EUE results indicate that the trends identified in 2030 are exacerbated by continued load growth. Basin shows 97.3 GWh of EUE in the 67% Additions Scenario over 147 LOLHs, which is an average of 660 MWh of EUE per LOLH. The Northwest shows 91.4 GWh of EUE over 369 LOLHs, averaging 248 MWh of EUE per LOLH. This again emphasizes that loss of load is anticipated to be a more frequent occurrence in the Northwest but by a smaller margin than experienced in the Basin subregion. Also in the 67% Additions Scenario, the Rocky Mountain subregion shows 4.3 GWh of EUE over 36 LOLHs, which is an average of 120 MWh per LOLH.
In the High Load Scenario, the Northwest's EUE skyrockets to 157 GWh over 714 LOLHs. The LOLEvs for the Northwest subregion in the High Load Scenario effectively become longer, however result in smaller average EUE per LOLH (220 MWh) than experienced in the 67% Additions Scenario.

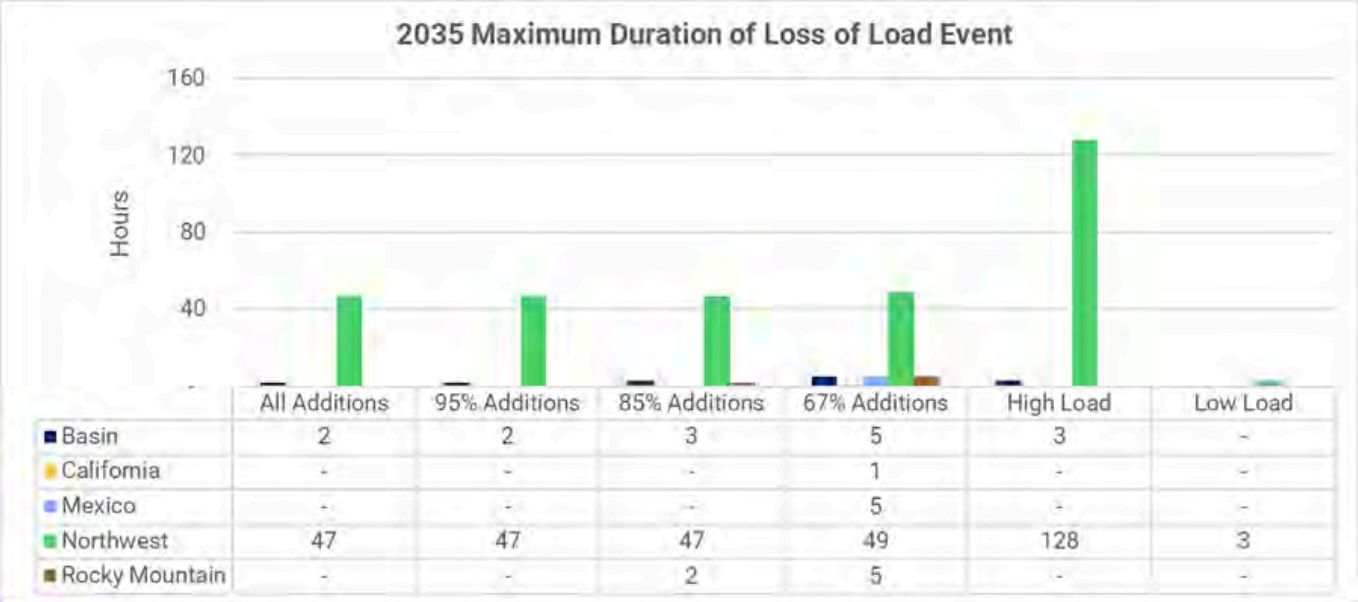
Duration



	All Additions	95% Additions	85% Additions	67% Additions	High Load	Low Load
Basin	-	1	3	4	3	-
Northwest	3	4	7	7	48	1
Rocky Mountain	-	-	-	1	-	-

Maximum duration of LOLEvs by subregion and scenario for 2030

Average duration of LOLEvs is between one and five hours depending on the scenario and subregion. However, when the maximum duration of LOLEvs is examined, the Northwest stands out. In the 2030 resource addition scenarios, Northwest LOLEvs have a maximum duration of three to seven hours. However, in the High Load Scenario, the Northwest has an LOLEv that lasts 48 consecutive hours in January. Given the cold weather during January and the significant electrification of heating in the Northwest, this is a noteworthy risk.



	All Additions	95% Additions	85% Additions	67% Additions	High Load	Low Load
Basin	2	2	3	5	3	-
California	-	-	-	1	-	-
Mexico	-	-	-	5	-	-
Northwest	47	47	47	49	128	3
Rocky Mountain	-	-	2	5	-	-

Maximum duration of LOLEvs by subregion and scenario for 2035

In 2035, the Northwest again stands out as the subregion with longest-lasting LOLEvs. The resource addition scenarios all show at least one LOLEv that lasts between 47 and 49 hours. The High Load Scenario for the

Northwest shows an LOLEv lasting 128 consecutive hours — equivalent to over five days of outage — in January. This is a significant concern given electricity is a primary fuel for residential heating in the Northwest.

Subregional Data



This section gives a subregional view of present and future resource portfolios, resource additions and retirements, demand forecasts, and loss of load metrics. Loss of load metrics are presented as heat maps that show seasonality, timing, frequency, and magnitude. The loss of load heat maps have been constructed for the years 2030 and 2035 for the All Additions, 67% Additions, and High Load scenarios.



Subregion: Alberta

The Alberta subregion spans the province, which has a population of approximately 5 million. Although its demand peaks in winter, an hour in summer 2024 was within 1.3% of its winter peak and four of the top seven hours were in the summer. There are an estimated 16,369 miles of transmission lines in this subregion.

Current resource mix

Natural gas dominates the resource mix in the Alberta subregion, with 61% of the installed capacity. Wind generation makes up 25% of the resource mix, while solar and hydro make up 8% and 4%, respectively.

2035 resource mix

If all generating resources included in current resource plans are built, in 2035 natural gas's share of the resource mix will decrease to 45%, while solar's share will increase to 23%. Battery storage is expected to grow from 1% of the resource mix to 3% in 2035.

Planned additions

The subregion is expected to add close to 10 GW of new generation over the coming decade, primarily solar (5 GW) and wind (3 GW).

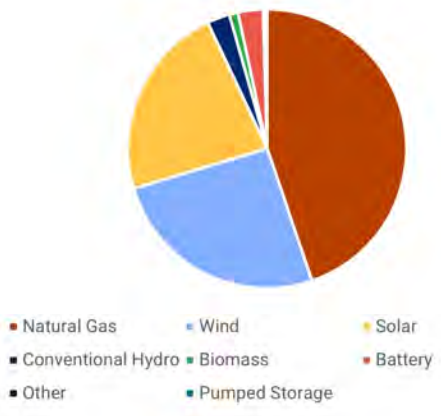
Planned retirements

No retirements are planned in the Alberta subregion through 2035 according to current resource plans.

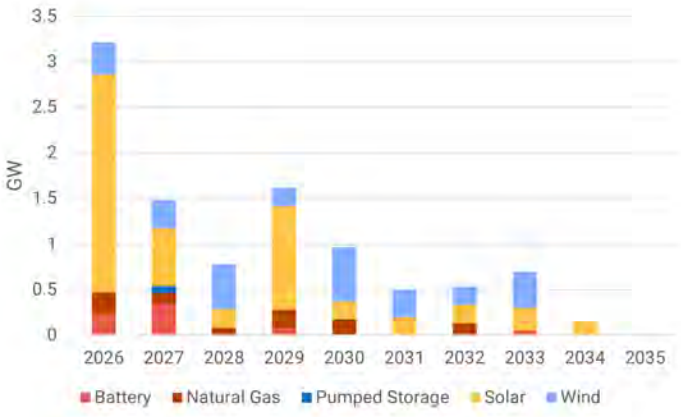
Annual and peak demand

Demand in the subregion is forecast to grow by 9% over the coming decade, while peak demand is projected to increase 8%. A major driver of demand growth in this subregion is transportation electrification.

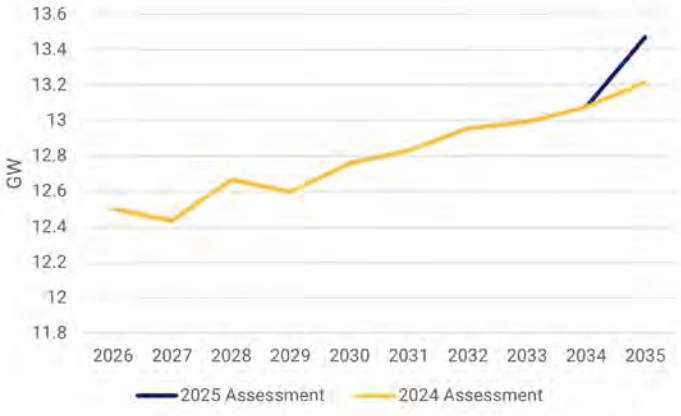
Loss of Load



Resource mix in 2035, if all planned additions are built

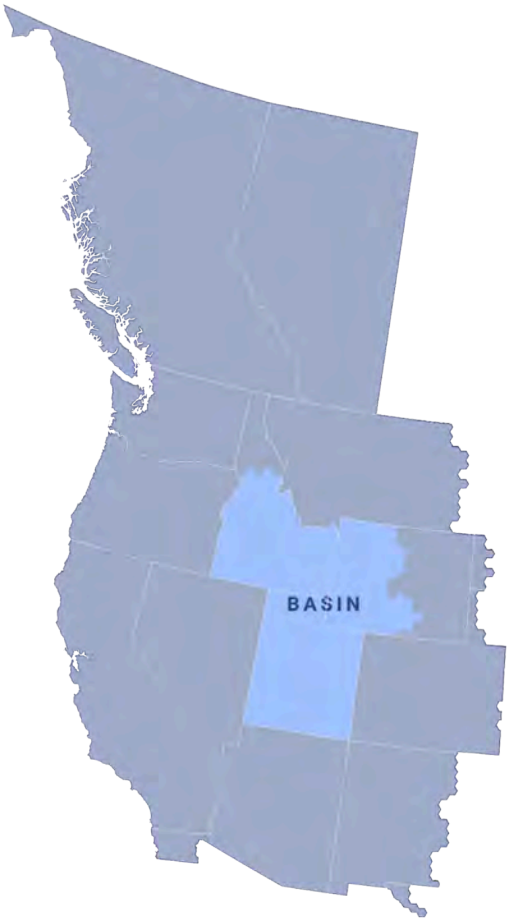


Planned resource additions, 2026-2035



Projected peak demand, 2026-2035

Alberta saw no loss of load in any of the scenarios.

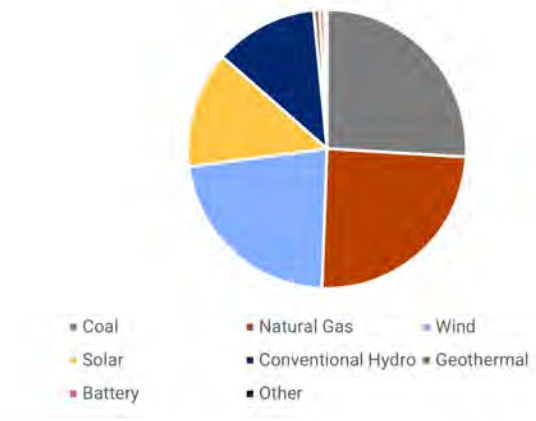


Subregion: Basin

Basin is a summer-peaking subregion that includes Utah, southern Idaho, and part of western Wyoming. The population of this area is approximately 5.4 million. There are an estimated 15,910 miles of transmission lines in this subregion.

Resource mix

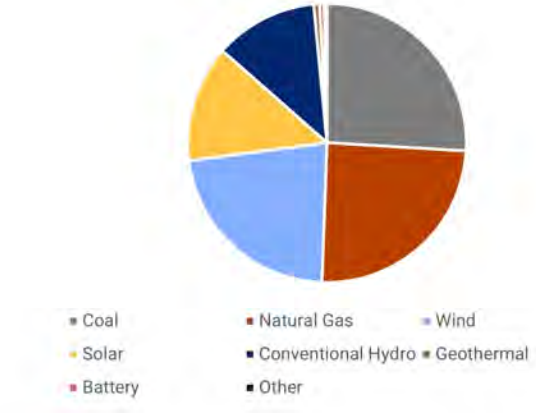
Basin's resource portfolio as of year-end 2024 is primarily coal and natural gas. The two make up 51% of nameplate capacity in the subregion. Wind and solar make a combined total of 36% of the resource mix, with the remaining portfolio primarily composed of hydro resources.



Resource mix, year-end 2024

2035 resource mix

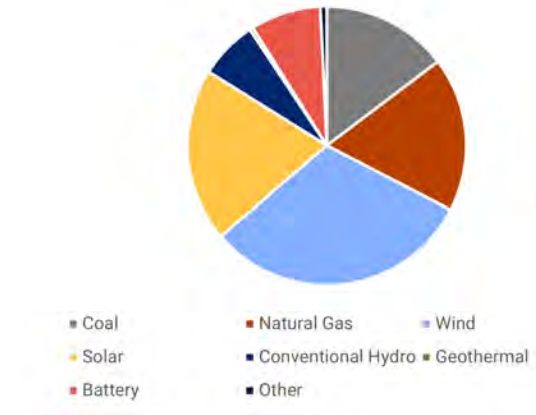
Over the next decade, wind and solar additions are anticipated to shift the resource mix to 51% variable energy resources (VER) and 33% thermal resources. BESSs are anticipated to make up 8% of the resource mix in the subregion by year-end 2035.



Resource mix, year-end 2024

Planned additions

Basin has over 15 GW of resource additions planned from 2026 through 2035. Slightly over 40%, or 6 GW, of the planned additions are wind resources, and over 25%, or 4 GW, are solar resources. BESS makes up 18%, or 3 GW, of the resource additions in the subregion, with half of the BESS capacity planned to be added in 2026.



Resource mix in 2035 if all planned resources are built

Planned retirements

Approximately 2.2 GW is planned for retirement through 2035, almost half of which are coal (980 MW). 700 MW of wind resources are planned for retirement over the decade, along with 360 MW of natural gas generation.

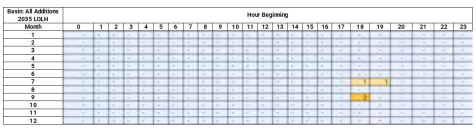
Annual and peak demand

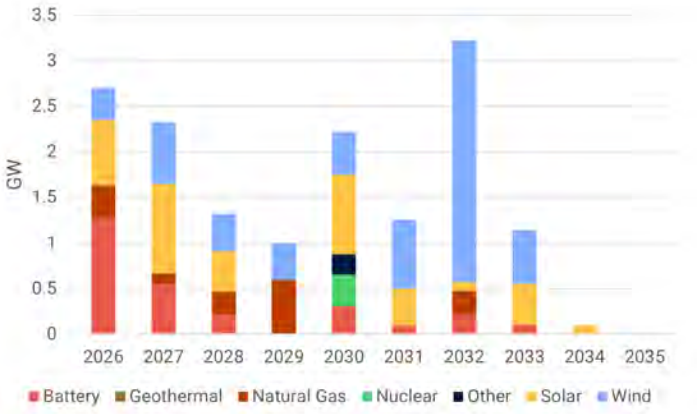
Demand in the subregion is forecast to grow by almost 26% over the coming decade, while peak demand is projected to increase 18%. Interconnection-wide annual energy load is projected to increase by 25%, and peak energy by 20%. Main contributors to demand growth in the Basin subregion are data centers and semiconductor manufacturing.

Loss of Load

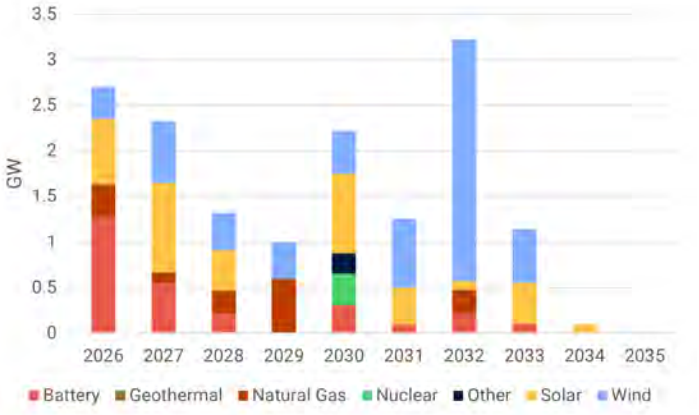
The heat maps below highlight the loss of load in several scenarios.

The heat maps for 2030 and 2035 67% Additions Scenario provide the clearest picture of the risk hours for the subregion. Basin is summer-peaking with peak load generally occuring between 3 p.m. and 4 p.m. However, during the summer, heat can linger after the peak hour, resulting in elevated demand lasting through the evening. Basin's planned resource additions are primarily wind and solar. The summer is not generally as windy as winter or shoulder seasons, and solar begins to dissipate in the evening. The elevated loads, coupled with a reduction in solar output during the evening hours, and general variability of wind, results in Basin showing the greatest risk to resource adequacy between 5 p.m. and 10 p.m. during July and August. Summer evenings also correspond with elevated demand in the Rocky Mountain and California subregions, lessening import availability from these subregions to Basin and further contributing to the loss of load.

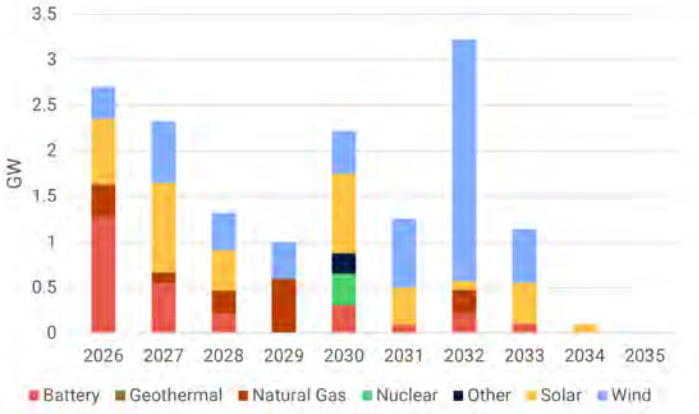




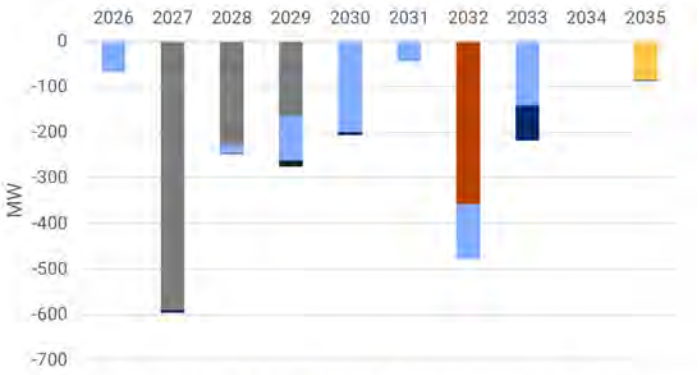
Planned resource additions, 2026-2035



Planned resource additions, 2026-2035

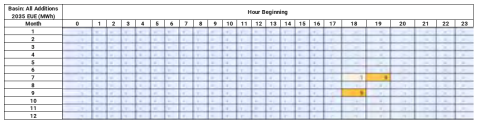


Planned resource additions, 2026-2035

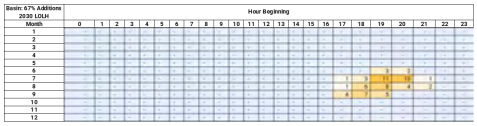



Natural Gas
Coal
Wind
Solar
Conventional Hydro
Other

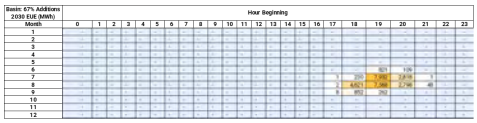
LOLH by month and hour for Basin in the 2035 All Additions Scenario



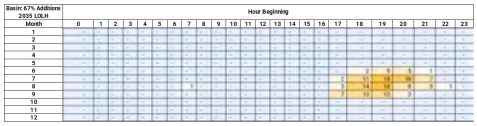
EUE by month and hour for Basin in the 2035 All Additions Scenario



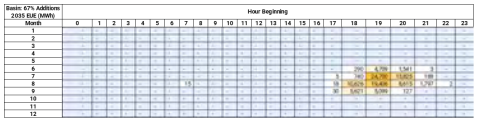
LOLHs by month and hour for Basin in the 2030 67% Additions Scenario



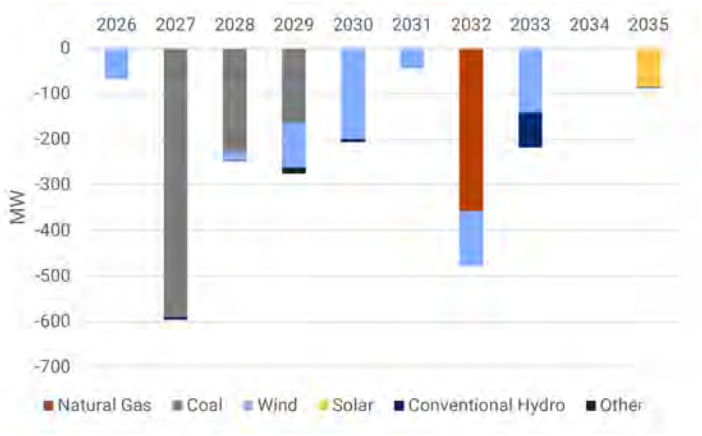
EUE by month and hour for Basin in the 2030 67% Additions Scenario.



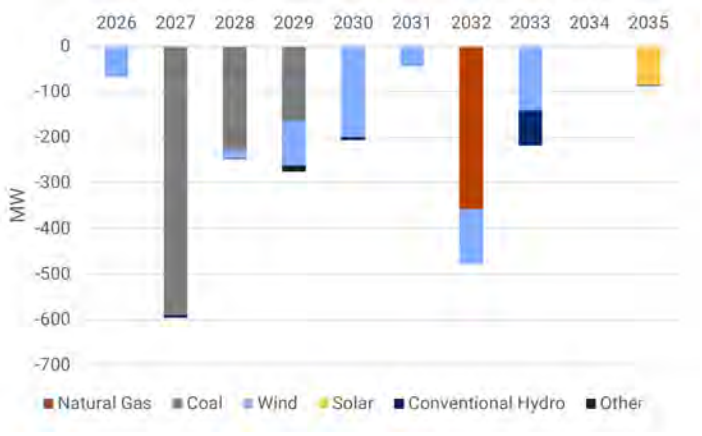
LOLHs by month and hour for Basin in the 2035 67% Additions Scenario



Planned retirements, 2026-2035

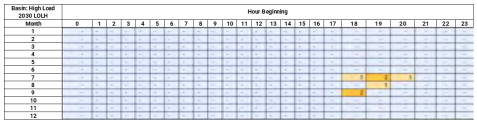


Planned retirements, 2026-2035

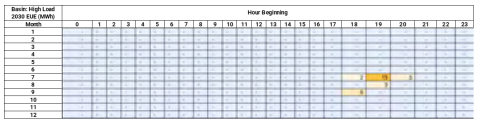


Planned retirements, 2026-2035

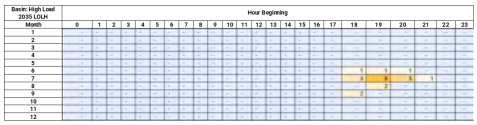
EUE by month and hour for Basin in the 2035 67% Additions Scenario



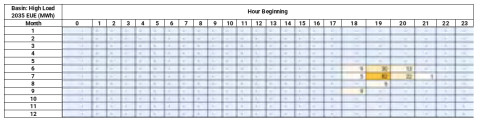
LOLHs by month and hour for Basin in the 2030 High Load Scenario



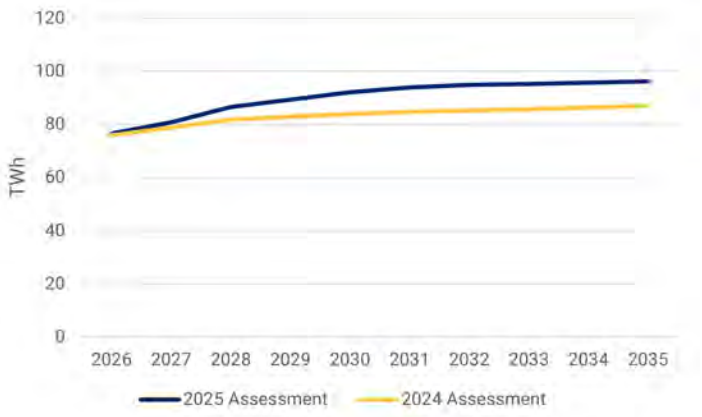
EUE by month and hour for Basin in the 2030 High Load Scenario



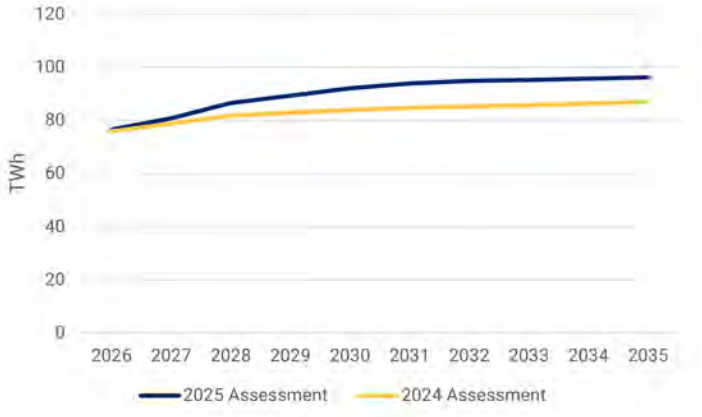
LOLHs by month and hour for Basin in the 2035 High Load Scenario



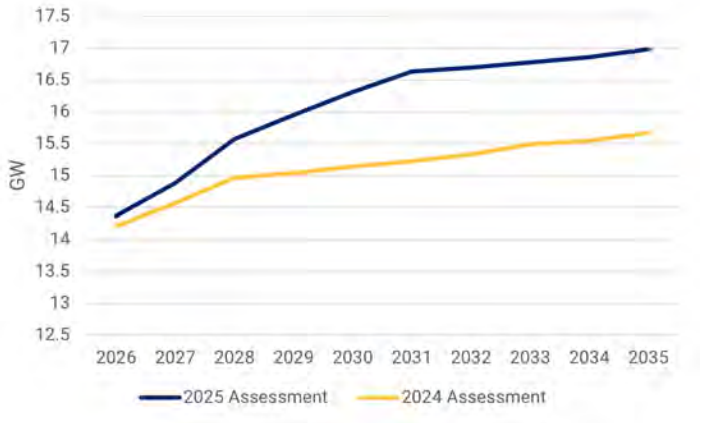
EUE by month and hour for Basin in the 2035 High Load Scenario



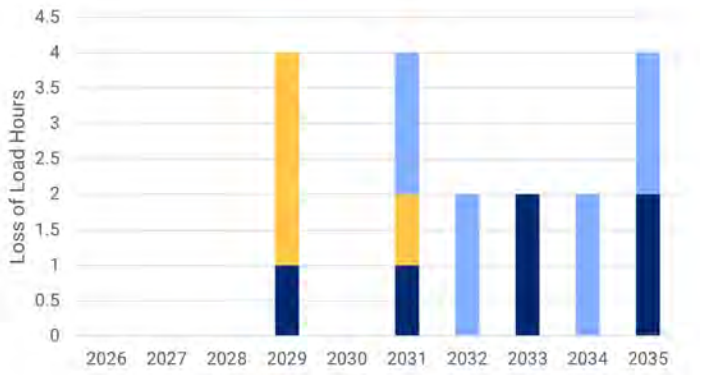
Projected annual demand, 2026-2035



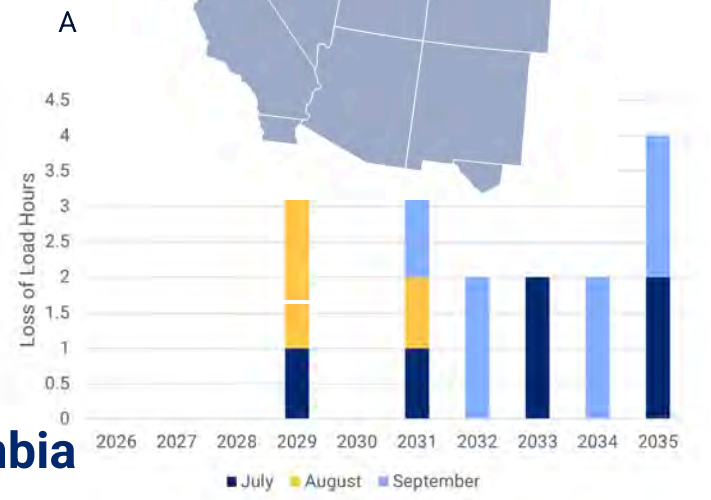
Projected annual demand, 2026-2035



Projected peak demand, 2026-2035



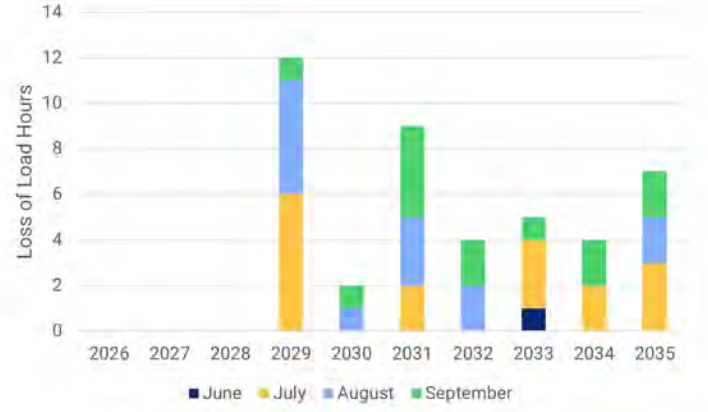




All additions scenario

Subregion: British Columbia

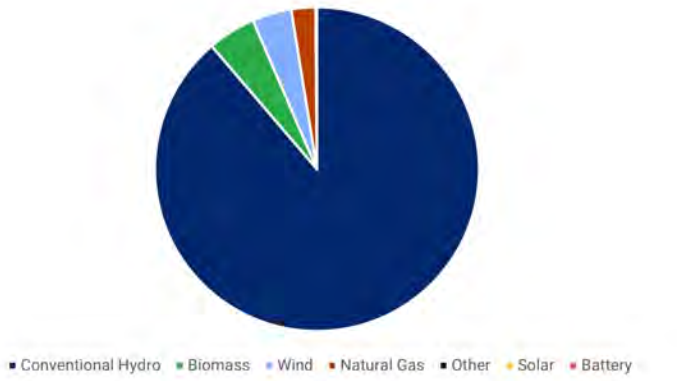
British Columbia is a winter-peaking area that spans the province, which has a population of approximately 5.7 million. There are an estimated 11,184 miles of transmission lines in this subregion.



95% scenario

Current resource mix

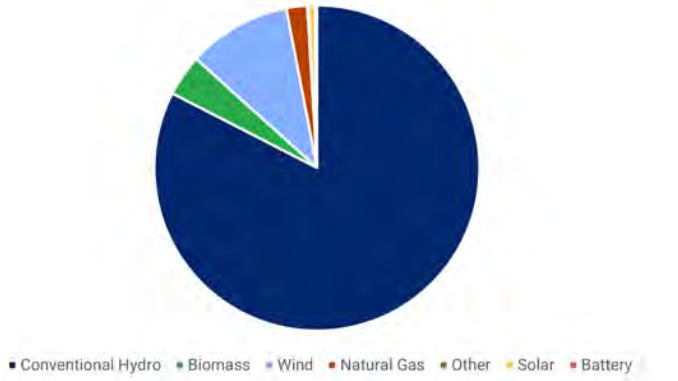
Hydro dominates the resource mix in the British Columbia subregion with 89% of the installed capacity. Biomass makes up 5%, wind 4%, and natural gas 2% of the resource portfolio as of year-end 2024.



Resource mix, year-end 2024

2035 resource mix

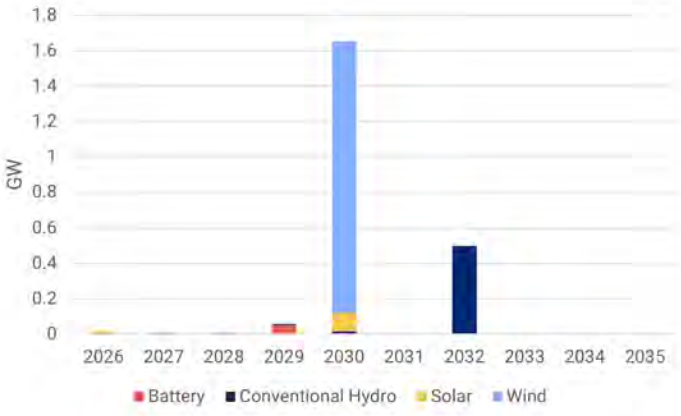
If all generating resources included in current resource plans are built, in 2035, hydro's share of the resource mix would decrease to 83%, primarily due to a large influx of wind capacity, which would then made up 10% of the resource portfolio.



Resource mix in 2035, if all planned resources are built

Planned additions

2.2 GW of new generation is planned in the subregion over the coming decade, including 1.5 GW of wind in 2030. There is also .5 GW of additional hydro capacity planned in 2032.



Planned resource additions, 2026-2035

Planned retirements

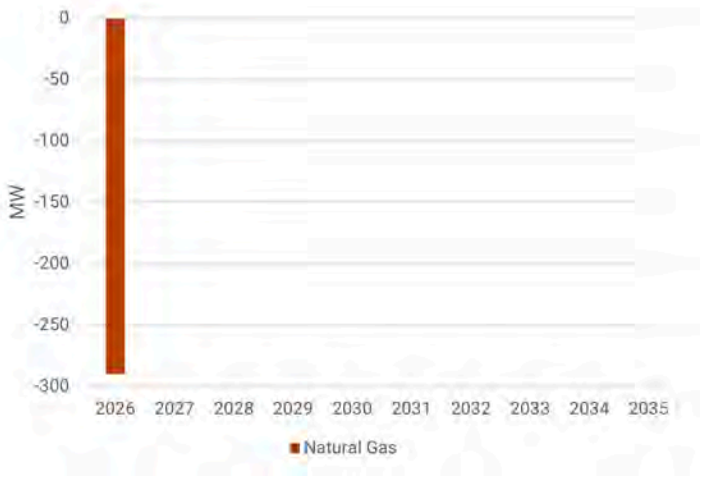
Approximately 290 MW of natural gas generation is slated for retirement over the next decade.

Annual and peak demand

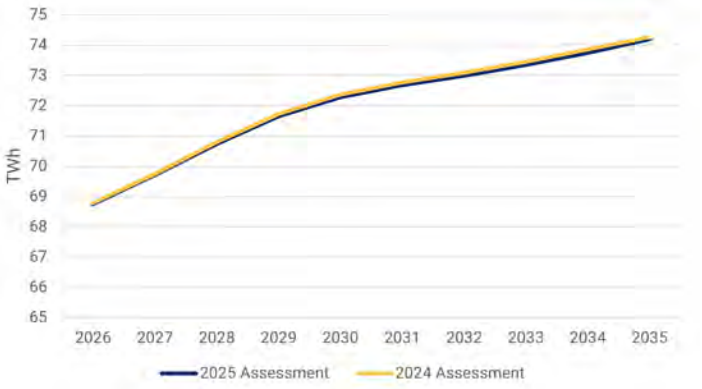
Demand in the subregion is forecast to grow by 8% over the coming decade, while peak demand is projected to increase 3.4%. Population growth, transportation and industrial electrification, and natural gas processing all contribute to demand growth in this subregion.

Loss of Load

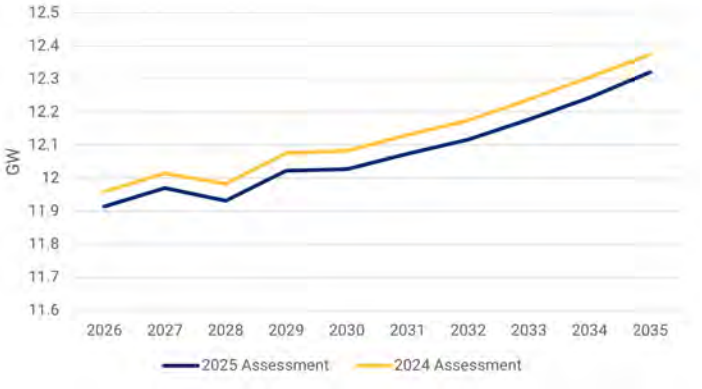
British Columbia saw no loss of load in any of the scenarios.



Planned retirements, 2026-2035



Annual demand forecast, 2026-2035



Peak demand forecast, 2026-2035

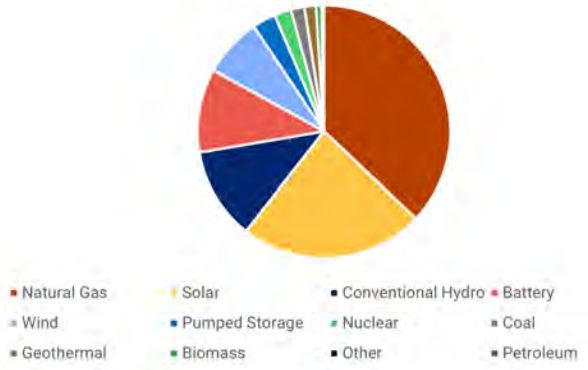


Subregion: California

California is a summer-peaking area that includes most of the state, which has a population of over 42.5 million people. There are an estimated 32,700 miles of transmission lines in this subregion.

Current resource mix

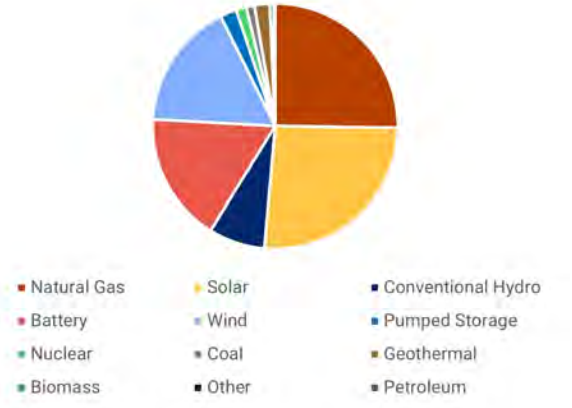
Natural gas makes up 37% of the resource mix in the California subregion on a nameplate capacity basis, followed by solar, which makes up 24%. Hydro and BESS make up 12% and 11%, respectively. Wind is 8% of the resource mix.



Resource mix, year-end 2024

2035 resource mix

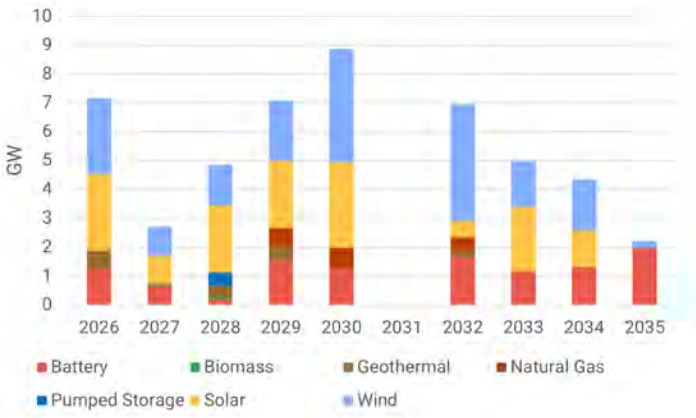
If all generating resources included in current resource plans are built, in 2035, natural gas's share of the resource mix will decrease to 25%, while battery storage and wind will each increase to 17% and solar to 26%.



Resource mix in 2035, if all planned resources are built

Planned additions

The subregion is expected to add 49 GW of new generation over the coming decade. That includes 19 GW of wind, 15 GW of solar, and 11 GW of BESS. Approximately 2 GW of natural gas and geothermal generation is expected to be added.



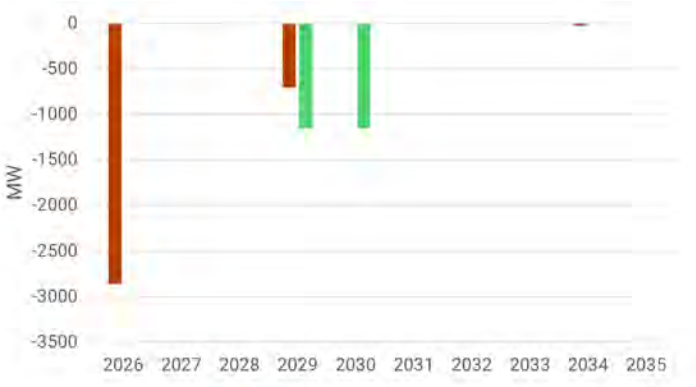
Planned resource additions, 2026-2035

Planned retirements

Nearly 6 GW of generation is planned for retirement over the coming decade, nearly all of it natural gas (3.6 GW) and nuclear (2.3 GW).

Annual and peak demand

Demand in the subregion is forecast to grow by 26% over the coming decade, while peak demand is projected to increase 21%. Transportation electrification and the anticipation of additional load during extreme heat

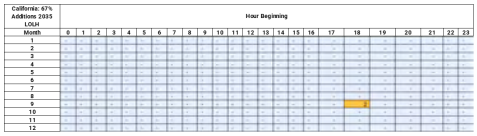


events are major factors of demand growth for this subregion.

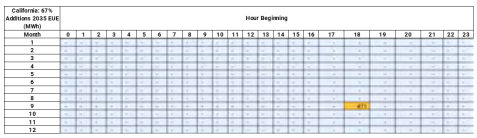
Loss of Load

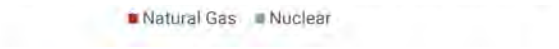
The California subregion did not show loss of load in the All Additions or High Load scenarios. California only shows loss of load under the 67% Additions Scenario, and not until 2032, 2033, and 2035. The loss of load heat maps for 2035 for the 67% Additions Scenario are shown below.

California shows two LOLHs in 2035 totaling 471 MWh of EUE in September. This occurs between the hours of 6 and 7 p.m. This time frame is slightly after peak, which generally occurs between 4 and 5 p.m. in this subregion. During the summer, heat can linger after the peak hour, resulting in elevated demand lasting through the evening. California is anticipated to retire 6 GW of natural gas and nuclear capability over the next decade, while adding approximately 34 GW of solar and wind. Solar availability diminishes in the evening, and wind output during this time can vary. The elevated load during summer evenings, coupled with thermal retirements and diminishing solar availability during this period, result in the identified LOLHs shown below.

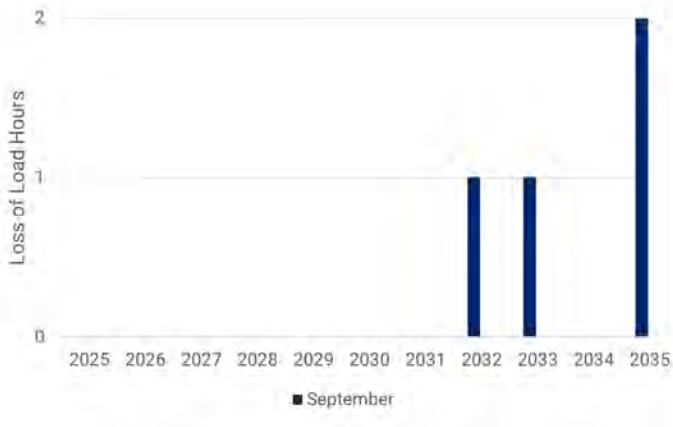


LOLHs by month and hour for the California subregion in the 2035 67% Scenario





Planned retirements, 2026-2035



67% Scenario

EUE by month and hour for the California subregion in the 2035 67% Scenario



Subregion: Mexico

Mexico is a summer-peaking area that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people. There are an estimated 1,568 miles of transmission lines in this subregion.

Current resource mix

Natural gas makes up 72% of the resource mix on a capacity basis. This is followed by geothermal at 13%, solar at 8%, and petroleum at 7%.

2035 resource mix

If all generation resources are built according to current resource plans, in 2035, solar's share of the resource mix will increase to 14%, while geothermal and petroleum will decline to 9% and 4%, respectively. Natural gas remains at 72%.

Planned additions

600 MW of solar is planned to be built over the coming decade in the Mexico subregion. This occurs primarily in years 2026 and 2028.

Planned retirements

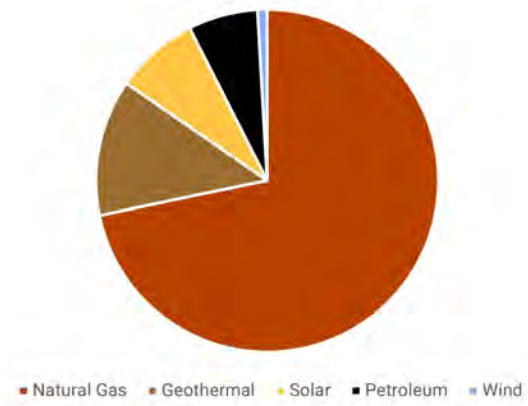
The subregion has no retirements through 2035.

Annual and peak demand

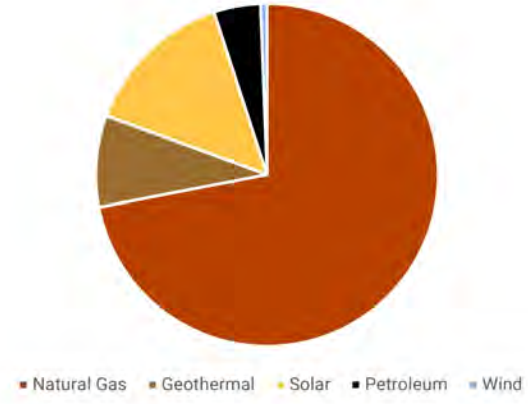
Demand in the subregion is forecast to grow 45% over the coming decade, while peak demand is projected to increase 41%. The anticipation of additional load during extreme heat events is the major factor driving demand growth for this subregion.

Loss of Load

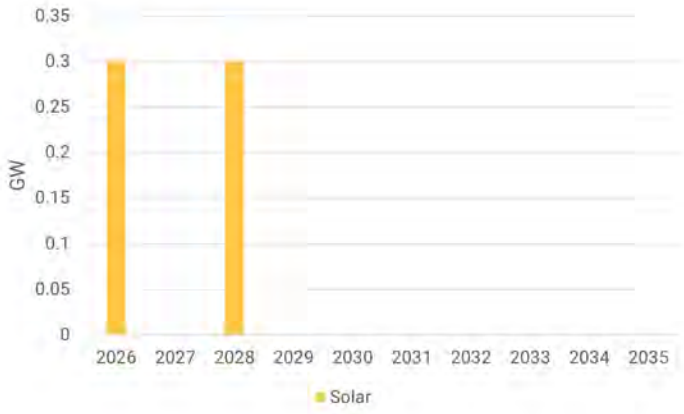
The Mexico subregion only shows loss of load under the 67% Additions Scenario in years 2034 and 2035. The



Resource mix, year-end 2024



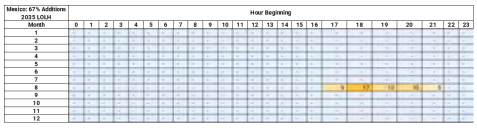
Resource mix in 2035 if all planned resources are built



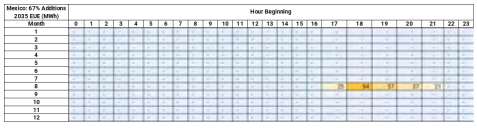
Planned resource additions, 2026-2035

loss of load heat maps for 2035 are provided below for the 67% Additions Scenario.

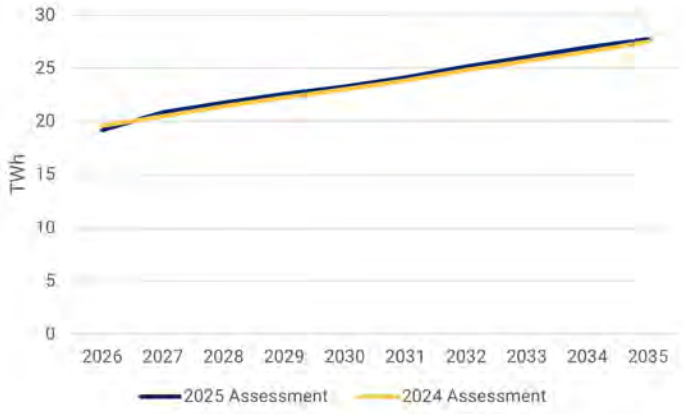
Mexico is a summer-peaking subregion that generally experiences peak load between 4 and 5 p.m. August is typically the hottest month in the subregion, thereby experiencing the greatest demand. Similar to California and Basin, summer heat can last beyond the peak hour, resulting in elevated demand through the evening. Solar is diminished during this period, and solar resources are the only additions planned for this subregion. The significant increase in demand over the next 10 years, coupled with the solar resource additions, which have diminished efficacy as daylight wanes, are the primary reason for the LOLHs during summer evenings after peak. The California subregion does support Mexico if there is surplus energy to do so, but despite the Mexico subregion importing up to the transfer limit from California, loss of load still occurs.



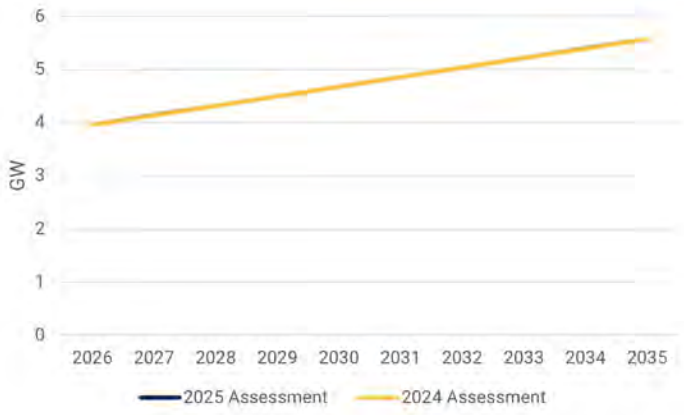
LOLHs by month and hour for the Mexico subregion in the 2035 67% Scenario



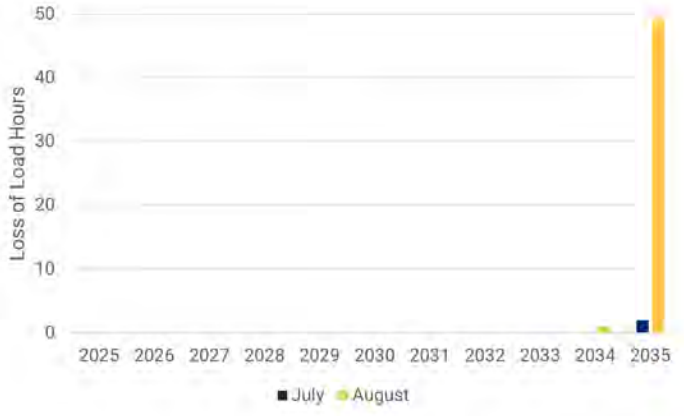
EUE by month and hour for the Mexico subregion in the 2035 67% Scenario.



Annual demand forecast. 2026-2035



Peak demand forecast, 2026-2035



67% scenario

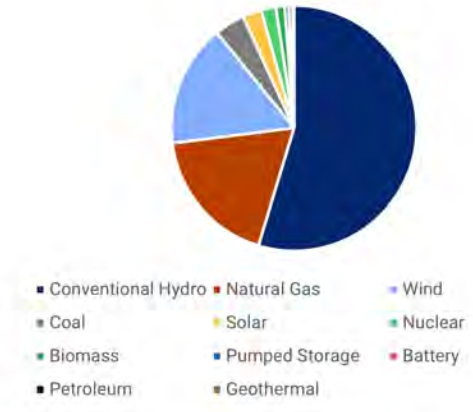


Subregion: Northwest

Northwest is a winter-peaking area that includes Montana, Oregon, Washington, and parts of northern California and Idaho. The population of the subregion is approximately 13.7 million. There are 16 Balancing Authorities in this subregion, which has an estimated 32,751 miles of transmission lines.

Current resource mix

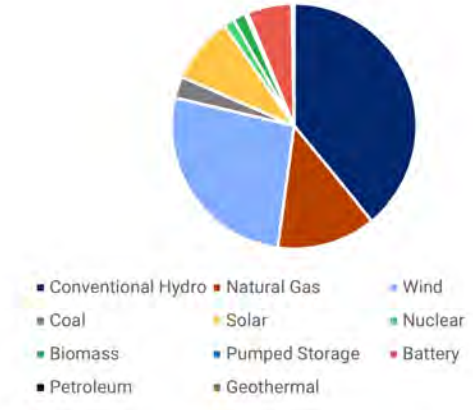
As of year-end 2024, the Northwest's resource portfolio primarily consists of hydro, natural gas, and wind resources. Hydro resources are a significant contributor to the Northwest's energy supply making up 55% of the resource portfolio. Natural gas makes up 18%, and wind accounts for 16%.



Resource mix, year-end 2024

2035 resource mix

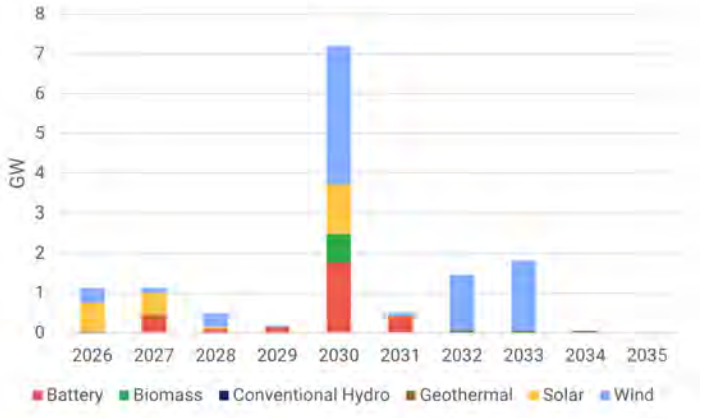
Resource plans indicate a significant influx of wind, solar, and BESS resources by year-end 2035. Wind grows to a 27% portfolio share, BESS increases to 6%, and solar increases to 9%.



Resource mix in 2035 if all planned resources are built

Planned additions

14 GW of new generation is planned in the subregion over the coming decade, including almost 8 GW of wind and 3 GW of battery storage.



Planned resource additions, 2026-2035

Planned retirements

The Northwest has approximately 340 MW of retirements slated to occur between 2026 and 2035. Over one-third of these retirements is biomass facilities. Hydro, wind, and solar retirements make up approximately half the retirements. It is worth noting that part of the renewable retirements may be repowers or non-renewals of purchase power agreements. The remaining retirements are primarily natural gas resources, the majority of which are set to retire in 2035.

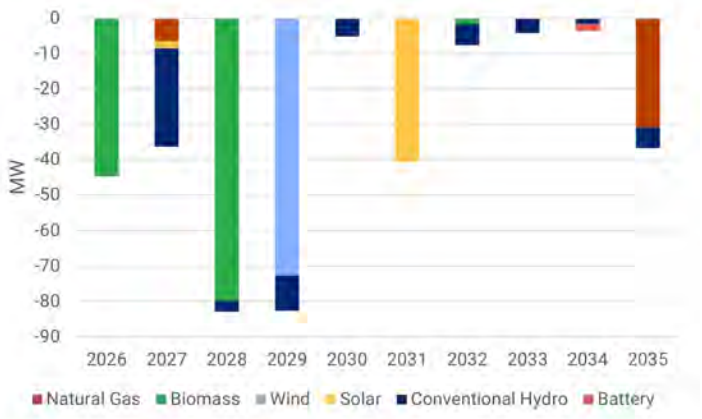
Annual and peak demand

Demand in the subregion is forecast to grow by 24% over the coming decade, while peak demand is projected to increase 21%. Major drivers of demand growth in the Northwest include data centers, residential and transportation electrification, customer growth, and semiconductor manufacturing.

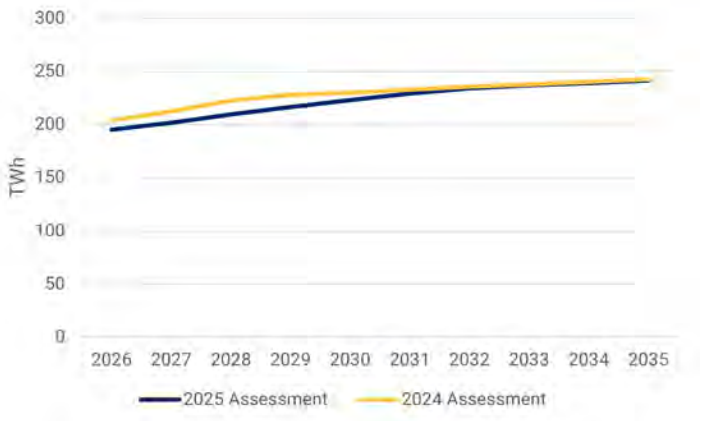
Loss of Load

The Northwest shows loss of load in all scenarios beginning as early as 2028 in the 67% Additions Scenario. Heat maps showing the timing and seasonal loss of load are provided below for the 2030 and 2035 All Additions, 67% Additions, and High Load scenarios.

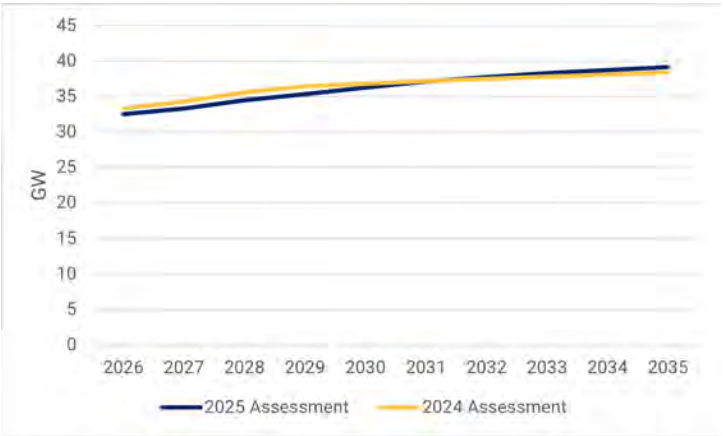
The Northwest is unique in that it experiences loss of load in the summer *and* winter in all scenarios, as well as the shoulder seasons in the High Load Scenario. The Northwest is also unique because, over the last decade, it has experienced system peaks both during the morning ramp (between 7 and 10 a.m.), which are more typical, *and* during the evening between 5 and 6 p.m. Morning ramps in the winter coincide with the greatest frequency of loss of load, whereas in the summer, the evening peak hours are when the greatest energy shortfalls are projected to occur. LOLHs and LOLEvs are greatest in the winter months, primarily in January and December, indicating that these months have a higher propensity for loss of load. Electricity is the predominant source of heat in the Northwest subregion, with the coldest temperatures occurring in the early morning and again dropping in the evening. In the winter, solar primarily contributes between the hours of 9 a.m. and 3 p.m., falling right in between the hours of greatest



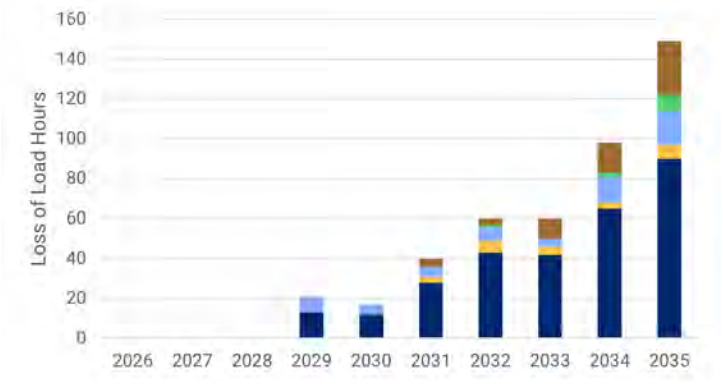
Planned retirements, 2026-2035

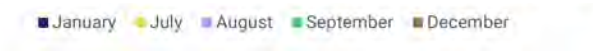


Annual demand forecast, 2026-2035



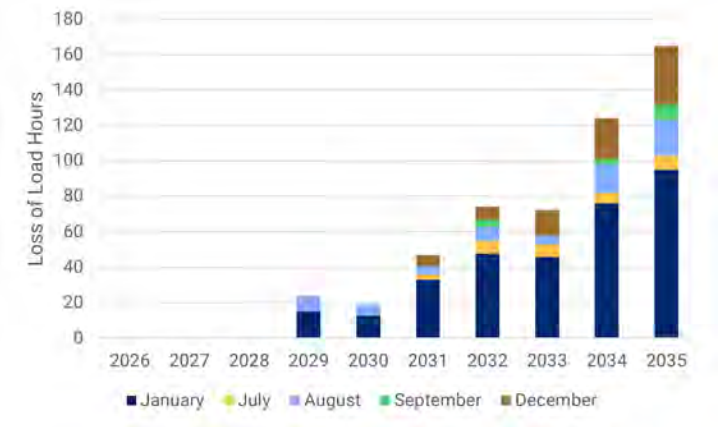
Peak demand forecast, 2026-2035




January
July
August
September
December

demand. Solar irradiance is weaker during the winter, which also lessens the contribution from solar resources. Wind makes up over 50% of the projected resource additions for the subregion, however these resources have the highest variability in energy output compared to other VERs. Wind can be prone to icing or overspeed during extreme cold weather events, which may minimize their availability during periods of elevated load. The significant demand associated with heating electrification, coupled with the timing of solar output and high wind variability, are the main drivers of

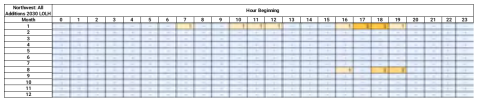
All Additions Scenario



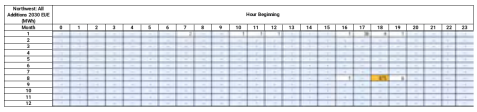
95% Scenario

LOLHs during the winter. In the summer, the primary driver of LOLHs is solar availability diminishing in the evening during periods of elevated demand. Given that BESS resources are modeled as being fully available for discharge, and that the All Additions Scenario shows LOLHs, these results indicate that the Northwest will need additional resources to meet demand over the next decade.

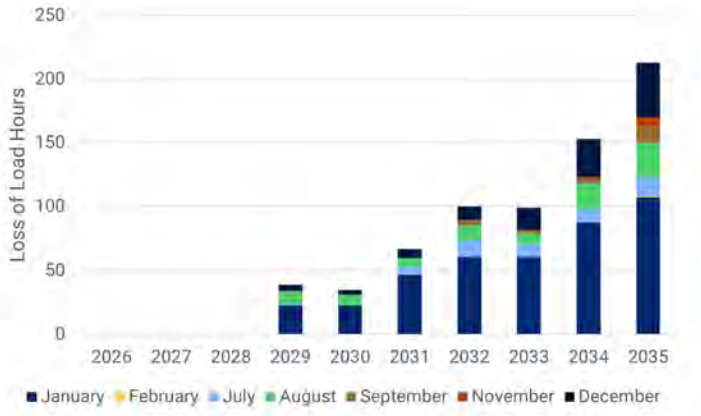
The California, Alberta, and British Columbia subregions support the Northwest during the morning winter ramps and evenings. However, transfer limitations from these subregions are frequently reached when attempting to mitigate loss of load in the Northwest, preventing further support to the subregion. In the summer, the California and Rocky Mountain subregions must meet their own native load obligations in the evenings, and can only provide limited support to the Northwest. The Alberta subregion also assists the Northwest during summer evenings but runs into transfer limitations. Beyond additional resources, additional transfer capability to the Northwest would also help reduce the projected loss of load in the subregion.



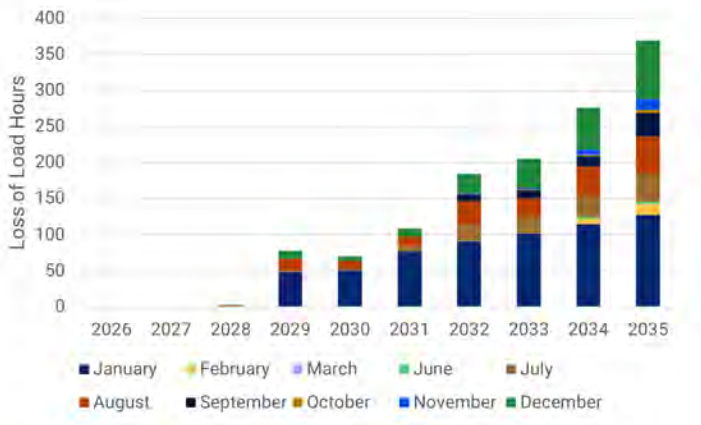
LOLHs by month and hour for the Northwest in the 2030 All Additions Scenario



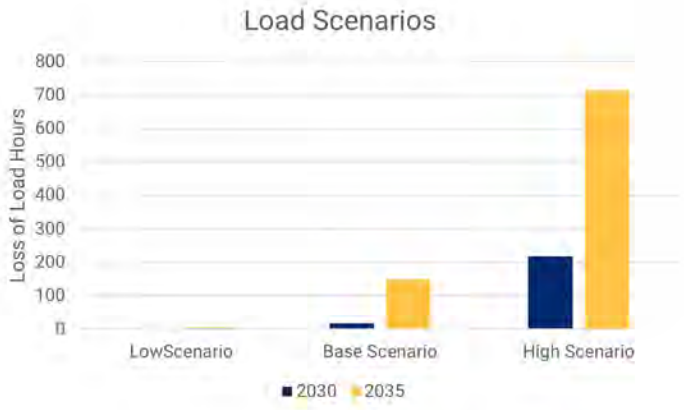
EUE by month and hour for the Northwest in the 2030 All Additions Scenario

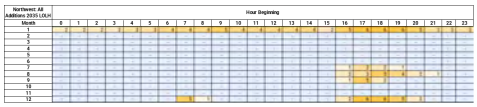


85% Scenario

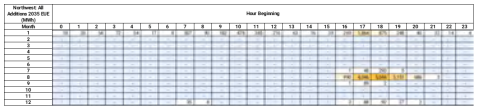


67% scenario

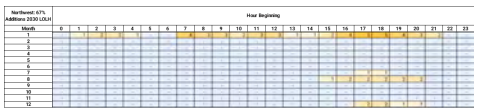




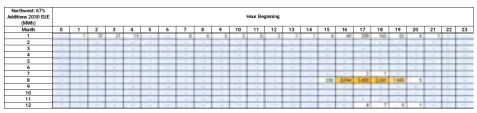
LOLHs by month and hour for the Northwest in the 2035 All Additions Scenario



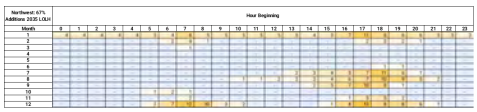
EUE by month and hour for the Northwest in the 2035 All Additions Scenario.



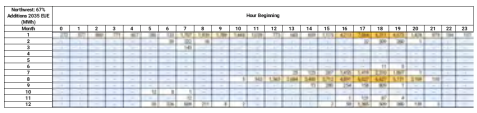
LOLHs by month and hour for the Northwest in the 2030 67% Additions Scenario.



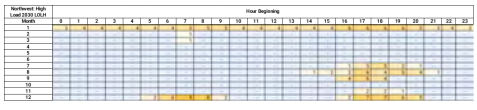
EUE by month and hour for the Northwest in the 2030 67% Additions Scenario



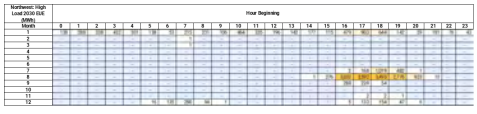
LOLHs by month and hour for the Northwest in the 2035 67% Additions Scenario



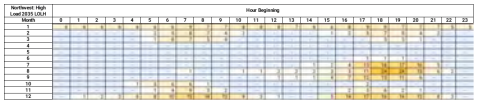
EUE by month and hour for the Northwest in the 2035 67% Additions Scenario



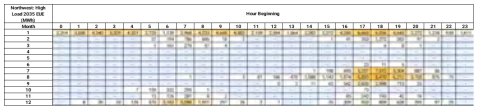
LOLHs by month and hour for the Northwest in the 2030 High Load Scenario



EUE by month and hour for the Northwest in the 2030 High Load Scenario



LOLHs by month and hour for the Northwest in the 2035 High Load Scenario



EUE by month and hour for the Northwest in the 2035 High Load Scenario

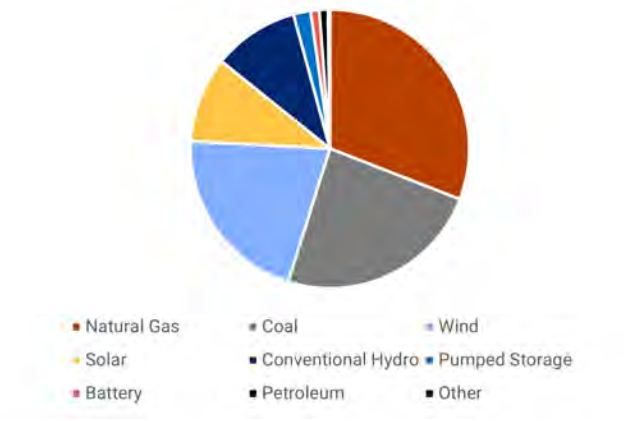


Subregion: Rocky Mountain

Rocky Mountain is a summer-peaking area that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. There are an estimated 18,800 miles of transmission lines in this subregion.

Current resource mix

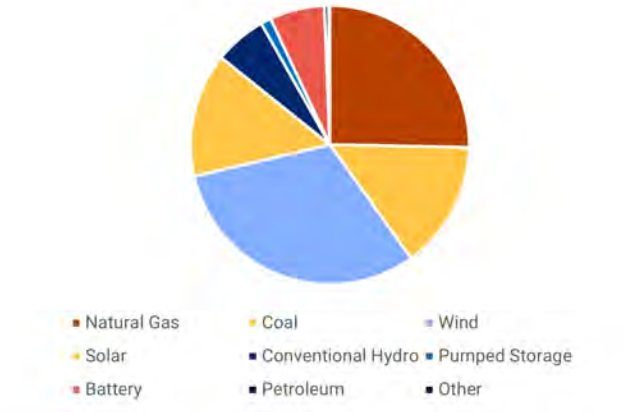
On a capacity basis, the resource portfolio in the Rocky Mountain subregion primarily consists of natural gas, coal, and wind resources. Natural gas and coal together make up 55% of the resource mix, with wind at 21%. Solar and hydro each make up 10%. Battery storage is at 1%.



Resource mix, year-end 2024

2035 resource mix

If all generation resources are built according to current resource plans, the capacity of thermal generation in the subregion will decrease to 40%, from 55% today. Wind would increase to 31% of the resource mix, while solar would increase to 14% and BESS to 6%.



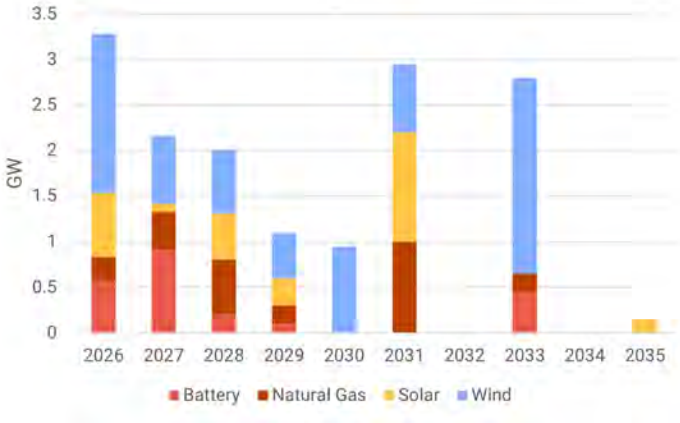
Resource mix in 2035, if all planned generation is built

Planned additions

15 GW of new resources is planned in the subregion over the coming decade, including almost 8 GW of wind and 3 GW of both natural gas and solar.

Planned retirements

Over 6 GW of generation is planned for retirement over the coming decade, including 2.8 GW of coal and 1.7 GW of both natural gas and wind.



Planned resource additions, 2026-2035

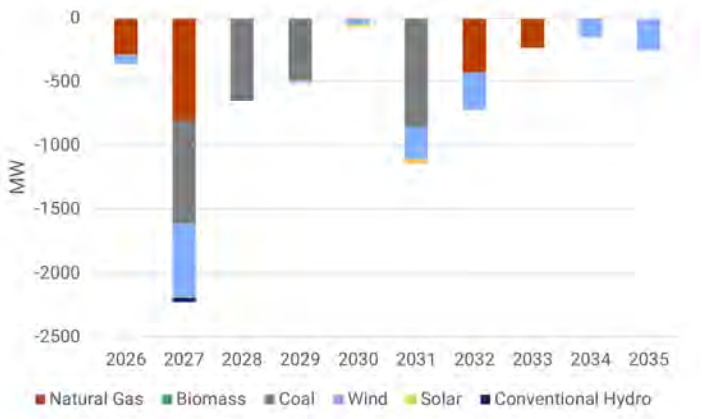
Annual and peak demand

Demand in the subregion is forecast to grow by 27% over the coming decade, while peak demand is projected to increase 23%. Major drivers of demand growth in the Rocky Mountain subregion include data centers, as well as commercial and industrial customer growth.

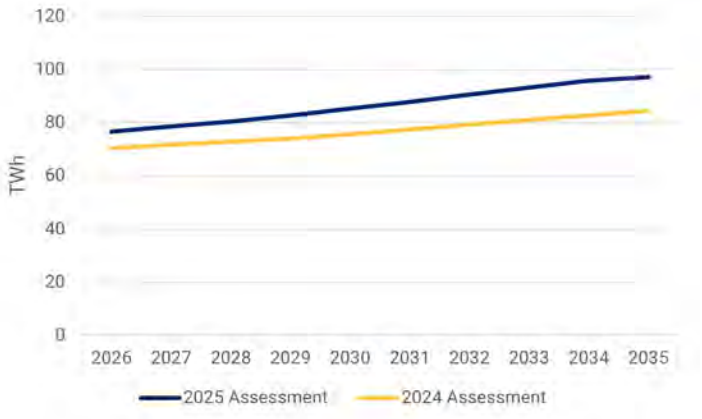
Loss of Load

The Rocky Mountain subregion does not show loss of load in the All Additions or High Load scenarios. This subregion shows loss of load under the 67% Additions Scenario for years 2030 through 2035, as well as one LOLH in 2034 and 2035 of the 85% Additions Scenario. The loss of load heat maps for the 2030 and 2035 67% Additions Scenario are provided below.

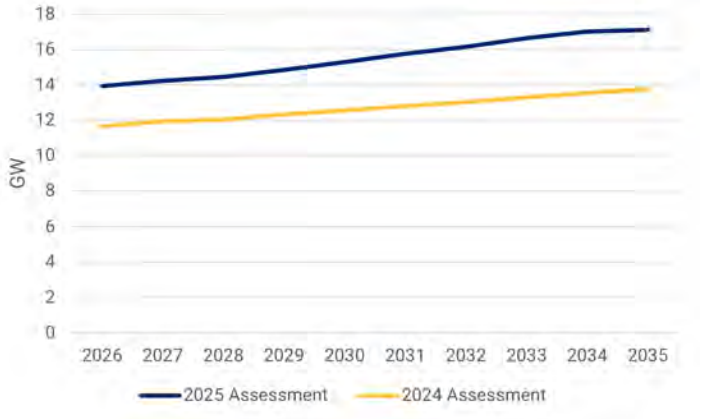
The Rocky Mountain subregion shows one LOLH for 5 MWh of EUE in 2030 and 18 LOLHs for 4,297 MWh of EUE in 2035 in the 67% Additions Scenario. The LOLHs occur between the hours of 4 and 9 p.m., primarily in July and August. This time frame includes the peak hour, which is anticipated to occur in the summer between 4 and 5 p.m. The Rocky Mountain subregion is showing a significant increase in both its annual demand and peak hour forecasts. The 2035 peak hour demand is projected at over 3 GW higher than last year's forecast, and the annual demand totals close to 13 TWh higher than last year's forecast. Similar to other subregions showing LOLHs during and shortly after their summer evening peak, these LOLHs are primarily a product of demand remaining elevated while solar output diminishes. In addition, there are over 6 GW of resource retirements with 4.5 GW of that being thermal resources. The additions in the 67% Additions Scenario total about 10 GW, with close to 7 GW of that being VERs. The reduction in additions, coupled with the increased uncertainty in energy output and unchanged retirements in the 67% Additions Scenario, also contribute to the LOLHs projected for this subregion.



Planned retirements, 2026-2035

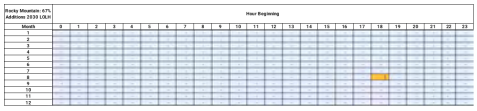


Annual energy demand forecast, 2026-2035

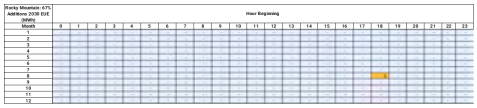


Peak demand forecast, 2026-2035

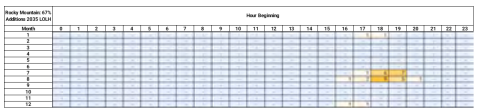




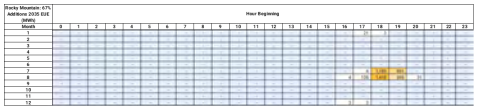
LOLHs by month and hour in the 2030 67% Additions Scenario



EUE by month and hour for the Rocky Mountain subregion in the 2030 67% Additions Scenario

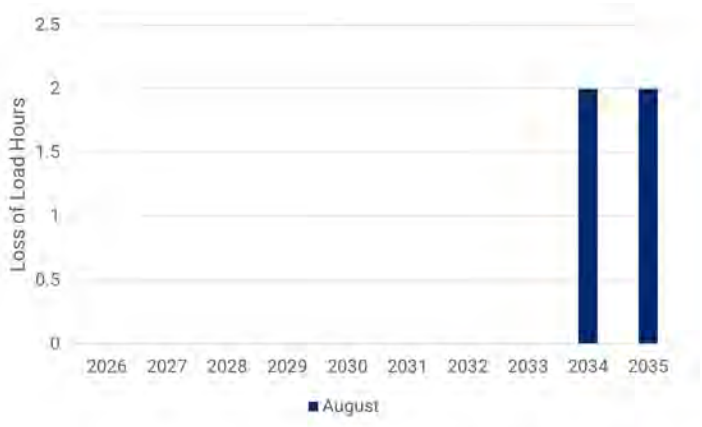


LOLHs by month and hour for the Rocky Mountain subregion in the 2035 67% Additions Scenario





85% Scenario

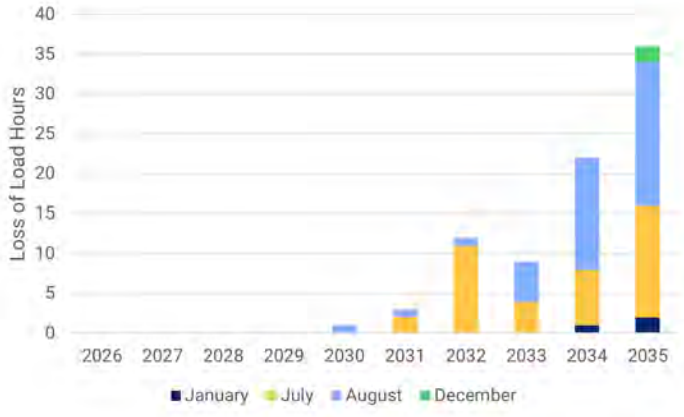


85% Scenario

EUE by month and hour for the Rocky Mountain subregion in the 2035 67% Additions Scenario



67% scenario



67% scenario

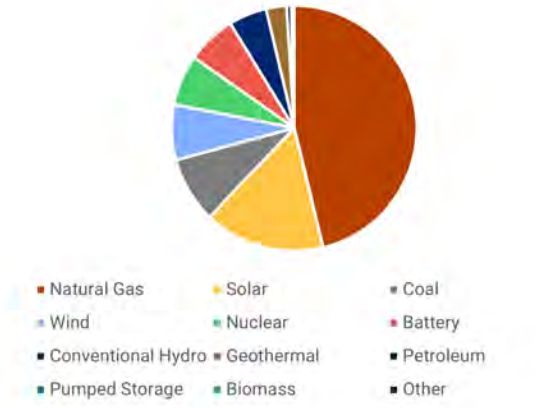


Subregion: Southwest

Southwest is a summer-peaking area that includes all of Arizona and New Mexico, most of Nevada, and a small part of Texas. The area has a population of approximately 13.6 million. There are an estimated 23,100 miles of transmission lines in this subregion.

Current resource mix

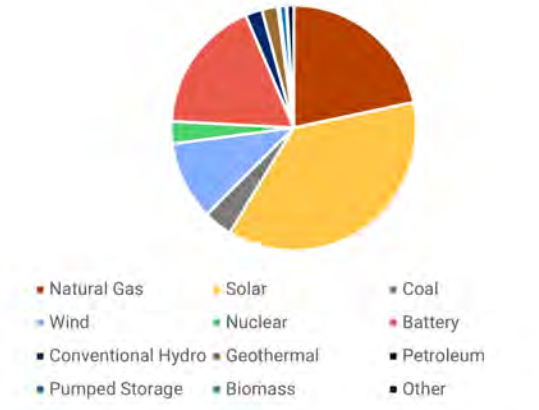
As of year-end 2024, natural gas makes up almost half of the resource mix in the subregion (46%), while solar makes up 16%. Coal, wind, nuclear, and BESS make up between 7% and 9% each of the current resource mix.



Resource mix, year-end 2024

2035 resource mix

If all generation resources are built according to current resource plans, in 2035, the resource mix will comprise 22% natural gas, 37% solar, and 18% battery storage. Along with natural gas's significant decline in the share of the resource mix, coal is expected to drop from 9% today to 4% in 2035.

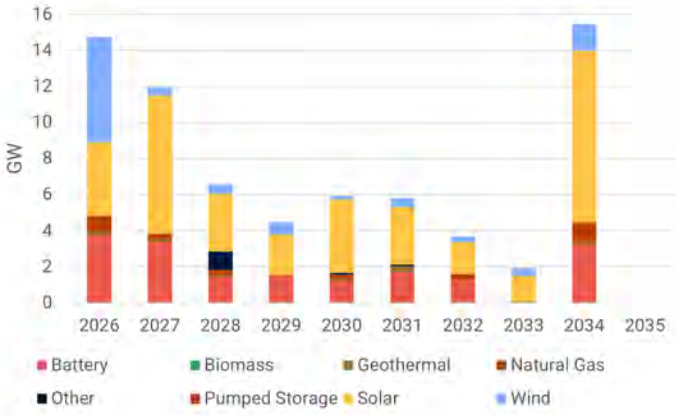


Resource mix in 2035, if all planned resources are built

Planned additions

70 GW of new resources are planned in the subregion over the coming decade, more than in any other subregion. Over half of the planned additions are solar (37 GW). 17 GW of BESS is planned, and 10 GW of wind.

In addition, 40 GW of the planned additions are tier 3 resources, which are more speculative.



Planned resource additions, 2026-2035

Planned retirements

7 GW of generation is planned for retirement over the coming decade, including 3 GW of coal and 2 GW of natural gas.

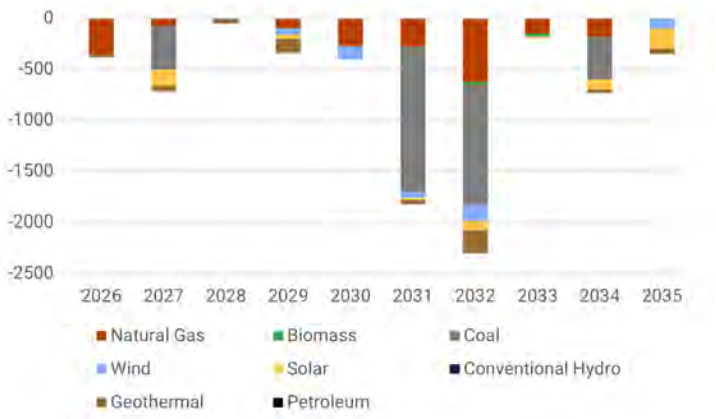
Annual and peak demand

Demand in the subregion is forecast to grow 42% over the coming decade, while peak demand is projected to

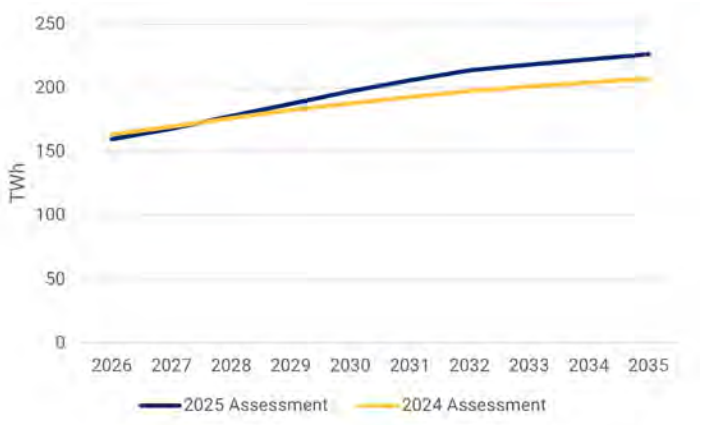
increase 29%. The major drivers of demand growth in the Southwest subregion include data centers, industrial and residential electrification, and residential customer growth.

Loss of Load

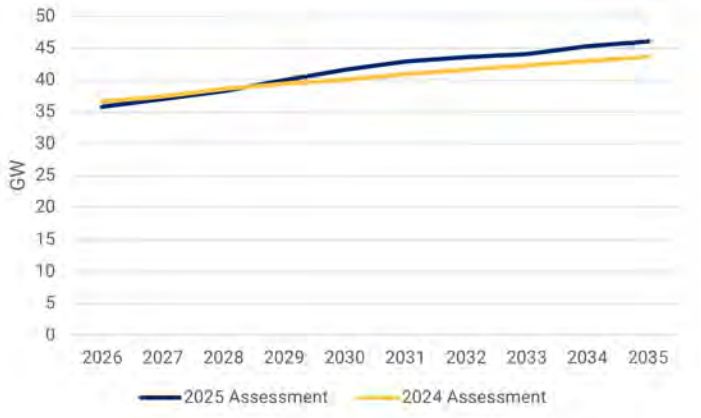
The subregion did not show loss of load in any scenario over the coming decade.



Planned retirements, 2026-2035



Annual demand forecast, 2026-2035



Peak demand forecast, 2026-2035

Transfers

Transfers by subregion for years 2030 and 2035 for the All Additions, 67% Additions, and the High Load scenarios are provided below. Transfers are separated into imports and exports and shown both by month and by hour of the day.

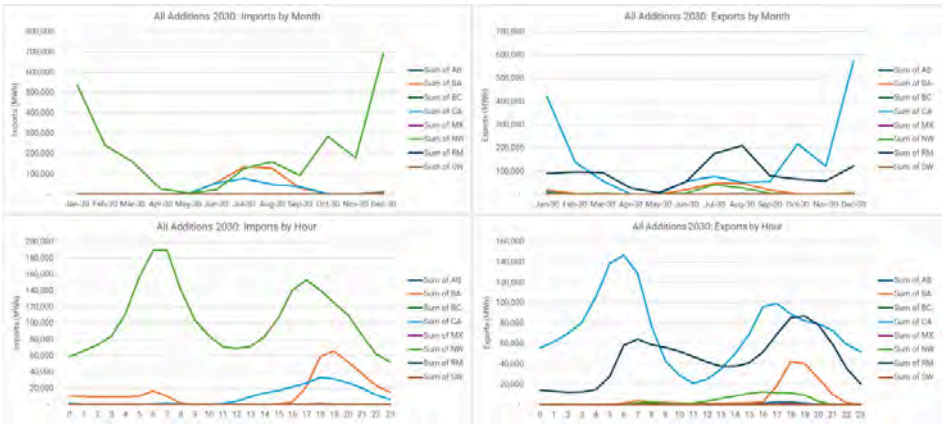
The Northwest shows the greatest amount of imports in all scenarios. This is particularly true in the winter months during the morning and evening ramps. As discussed in the Northwest Loss of Load Section, winter mornings and evenings are the times when this subregion experiences most of its loss of load. MAVRIC's transfer logic only allows for transfers when loss of load is identified for an area in an islanded state. Therefore, the timing and magnitude of imports align with the periods of greatest need for a subregion. Most of the transfers to the Northwest come from the California subregion, specifically during the morning ramp hours of the winter months when the California subregion has surplus energy. There are times where the transfer limits from the California subregion to the Northwest are met, and Alberta, British Columbia, and Rocky Mountain subregions also support the Northwest. However, transfer limits from the Alberta and British Columbia subregions to the Northwest are frequently reached when attempting to mitigate loss of load in the Northwest. This indicates that additional transfer capability to the Northwest from the California, Alberta, or British Columbia subregions would help alleviate winter LOLHs.

Summer evenings in the Northwest appear to be partially supported by the California subregion as well. However, the California subregion's ability to export during the evening becomes limited due to diminished solar and elevated native load. In other words, transfer limits to the Northwest from California during summer evenings are rarely met, as California is satisfying its obligations rather than exporting power. With less support from the California subregion, the Northwest leans more heavily on Alberta and the Rocky Mountain subregion for support. The Alberta subregion appears to hit its transfer limits to the Northwest frequently during summer evenings, indicating that loss of load could partially be alleviated with additional transfer capability from Alberta to the Northwest. The Rocky Mountain subregion can assist during summer evenings to an extent but does not hit its transfer limits to the Northwest. This indicates that, like California, the Rocky Mountain subregion must also meet its native load during summer evenings and can only provide limited support to the Northwest.

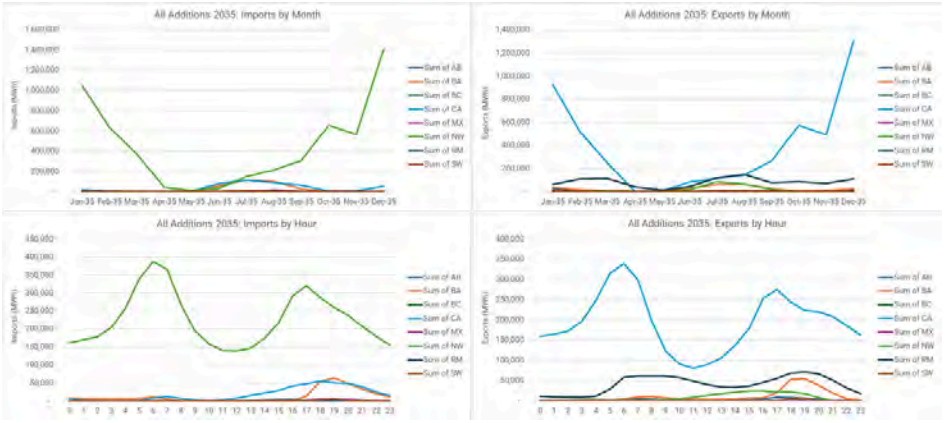
Basin also shows loss of load in all scenarios, primarily during summer evenings in the latter years of the Western Assessment. As such, Basin is primarily shown to import energy from June through August during and after its evening peak. During these hours, external transfers are sourced from the Rocky Mountain, Southwest, and California subregions. The Southwest subregion maxes out its transfer capability to Basin during the summer evening hours, indicating that there may be additional energy in the Southwest that could be provided to Basin if additional transfer capability were available. The Rocky Mountain and California subregions do not meet their transfer limits when assisting Basin on summer evenings, indicating that these subregions are meeting native load obligations with available resources rather than providing surplus energy to Basin. This is exacerbated in the High Load Scenario, in which transfers from the Rocky Mountain and California subregions become even more limited, resulting in an increase in LOLHs within the Basin subregion. This is despite Basin not having additional speculative large load demand in the subregion itself.

The Southwest shows a significant bump in exports during summer evenings in 2035 of the 67% Additions and High Load scenarios. Most of this increase in export activity is to support both the Basin and Rocky Mountain subregions. Mexico displays a notable increase in its imports in the 2035 67% Scenario, which are primarily fulfilled by the California subregion. Many LOLHs in the Mexico subregion occur despite the California subregion exporting up to its transfer limit to the Mexico subregion.

All Additions

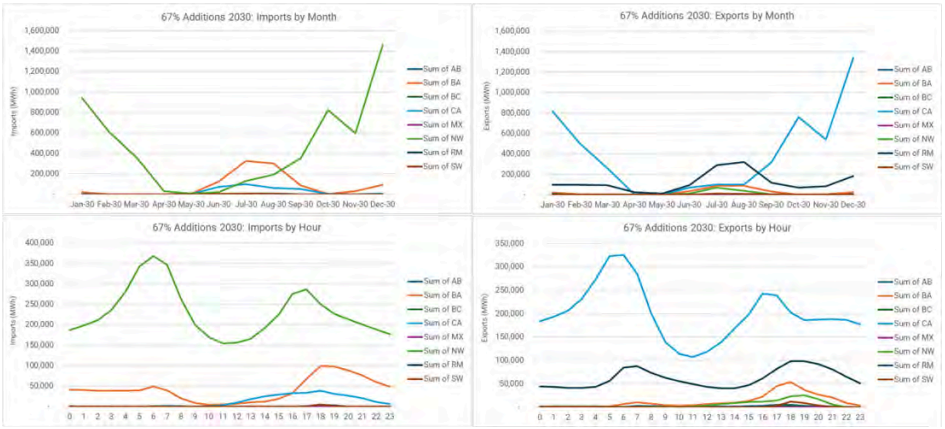


Subregional transfers by month and time of day for the 2030 All Additions Scenario

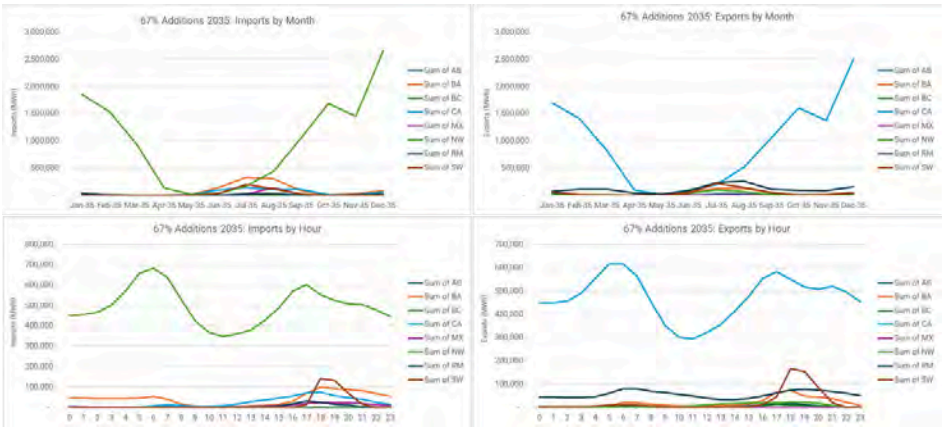


Subregional transfers by month and time of day for the 2035 All Additions Scenario

67% Additions

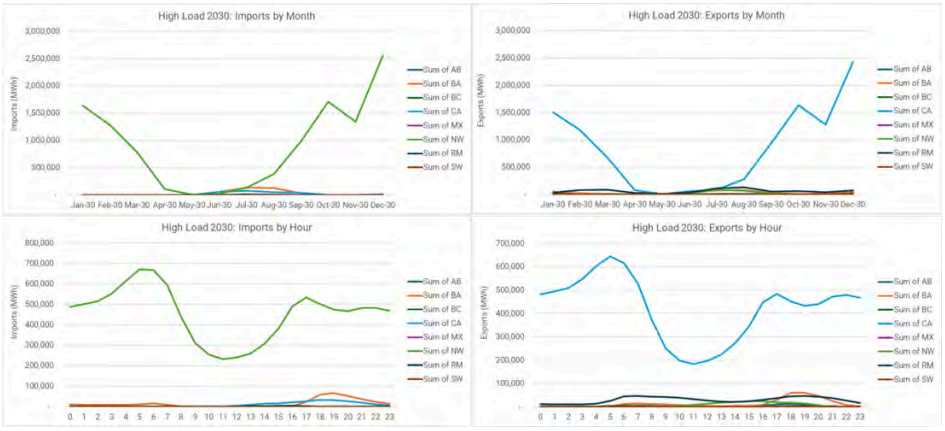


Subregional transfers by month and time of day for the 2030 67% Additions Scenario

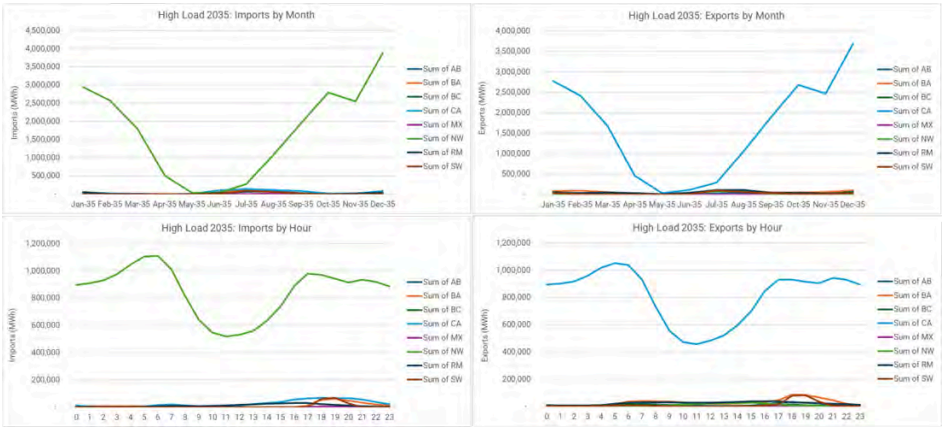


Subregional transfers by month and time of day for the 2035 67% Additions Scenario

High Load



Subregional transfers by month and time of day for the 2030 High Load Scenario



Subregional transfers by month and time of day for the 2035 High Load Scenario

Methods & Data

- Read the methodology used in this assessment.
- Read the glossary of terms used in this assessment.
- This year's Western Assessment uses eight new subregional boundaries that better align with operational and planning realities and are consistent with other WECC assessments.
- This assessment uses Loads & Resources data provided by the Balancing Authorities in early 2025.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit WWW: Department, Order No. 202-26-49 (Sep. 25, 2026)

Department of Energy
Washington, DC 20585

Tri-State Generation and Transmission Association,
Platte River Power Authority, Salt River Project,
PacifiCorp, and Public Service Company of Colorado,
and Southwest Power Pool
Regarding Craig Station

Order No. 202-26-49

Pursuant to the authority vested in the Secretary of Energy (Secretary) by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC)–Rocky Mountain[3] region due to a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

Craig Station (Craig) is an electric generating facility in Craig, Colorado. Craig is operated by the Tri-State Generation and Transmission Association (Tri-State). Craig consists of three coal-fired generation units, Unit 1 (446.4 megawatts (MW)), Unit 2 (446.4 MW), and Unit 3 (534.8 MW), with a combined nameplate capacity of 1427.6 MW.[4] Unit 1 and Unit 2 are co-owned by Tri-State, Platte River Power Authority, Salt River Project, PacifiCorp, and Public Service Company of Colorado, hereinafter collectively referred to as the co-owners.[5] Unit 3 is wholly owned by Tri-State. Unit 1 and Unit 2 began operations in 1980 and 1979, respectively. Unit 3 began operations in 1984. Unit 1 was slated to cease operations in December 2025. Unit 2 and Unit 3 are

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] The 2024 Long-Term Reliability Assessment (LTRA) from the North American Electric Reliability Corporation (NERC) included Colorado in the WECC–Northwest region. The 2025 LTRA provides new regional boundaries for WECC to provide more geographic detail of reliability risk information and to, "reflect a more accurate alignment with operational and planning realities, as well as the footprints of various entities." In the 2025 LTRA, Colorado is included in the WECC–Rocky Mountain region.

[4] U.S. Energy Info. Admin., *Form EIA-860, Schedule 3: Generator Data* (2024), https://www.eia.gov/electricity/data/eia860/ [hereinafter EIA, *Form EIA-860*].

[5] Platte River Power Authority, Craig Units 1 & 2 (Yampa Project), https://prpa.org/generation/yampa-project/.

slated to retire in 2028.[6] Craig is dispatched by the Southwest Power Pool (SPP) that serves the WECC– Rocky Mountain region.

Order Nos. 202-25-14, 202-26-21, and 202-26-31, issued pursuant to FPA section 202(c) on December 30, 2025, March 30, 2026, and June 26, 2026, respectively, required that Craig Unit 1 continue to be available to operate for 90 days, until March 30, 2026, June 28, 2026, and September 26, 2026, respectively. Those orders were based on my determination that emergency conditions existed within the WECC–Northwest and WECC–Rocky Mountain regions, respectively.

Specifically, I determined that the WECC–Northwest and, later, WECC–Rocky Mountain, region faced significant amount of retiring baseload generation resources and concerns meeting demand during shoulder periods.[7] I determined that the continued operation of Craig Unit 1 would provide additional generation capacity during these periods, which would help prevent the loss of power to homes and businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.[8] I determined that the continued operation of Craig Unit 1 was necessary to alleviate immediate and anticipated threats to reliability.[9]

My determination was based on several facts. First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that in the WECC–Northwest region, which included Colorado, Idaho, Montana, Oregon, Utah, Washington, and Wyoming, "[e]nergy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio." The 2024 LTRA notes that

> [f]ive [gigawatts (GW)] of baseload resource retirements are anticipated between 2024 and 2028. The energy needs are to be replaced by solar, wind, and [battery energy storage systems], further increasing variability

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[6] It would be difficult for the coal-fired unit to resume operations once retired. Specifically, practical issues, such as acquiring employment contracts and permits may greatly increase the timeline for resumption of operations, such that the facility may not be available in the period needed. Moreover, if the co-owners were to begin disassembling the unit or other related facilities, the associated challenges would be greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick et al., *Bus. Models for Coal Plant Decommissioning*, at 9–12 (Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

[7] *Tri-State Generation & Transmission Ass'n*, DOE Order No. 202-25-14, at 1–2 (Dec. 30, 2025).

[8] *Id.* at 1–3.

[9] *Id.* at 3.

> in the portfolio. Given the retiring of baseload resources, supply chain issues preventing the construction of [battery energy storage systems] resources are a concern as they assist in meeting demand during shoulder periods where solar availability is dropping but loads remain high.[10]

Second, the 2024 WECC Western Assessment of Resource Adequacy notes that peak demand in WECC's Northwest–Central subregion, which included Colorado at the time, is "forecast to grow by 8.5% over the next decade, from 33 GW in 2025 to 36 GW in 2034."[11] Meanwhile, WECC notes that most planned retirements are "baseload generation, such as coal, natural gas, and nuclear."[12]

Further, in January 2026, NERC released its 2025 Long-Term Reliability Assessment.[13] While NERC assessed that the WECC–Rocky Mountain region, which includes Colorado, is at normal risk of energy shortfalls over the next five years,[14] the region has an "[anticipated reserve margin] that falls below the [Reference Margin Level] in Summer 2034 and 2035, and Winter 2034–35."[15] The 2025 LTRA also notes that the WECC–Rocky Mountain region faces challenges from an aging thermal resource fleet, which can lead to unplanned outages, exacerbated by supply chain issues, and vendor availability.[16] Additionally, both solar and wind variability are year-round concerns, and prior to SPP expansion into the WECC–Rocky Mountain region, smaller entities had limited geographic diversity to counteract these generation constraints.[17]

Finally, between 2019 and 2024, the retirement of coal-fired generating capacity in Colorado has led to a decline in the share of coal-generated electricity from 45% to 25%.[18] Looking forward, by 2029, about 3,700 MW of coal-fired generating capacity

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[10] NERC, *2024 Long-Term Reliability Assessment*, at 130 (Dec. 2024, corrected Jul. 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

[11] WECC, *W. Assessment of Res. Adequacy 2024: Peak Demand by Subregion*, at 2, https://www.wecc.org/sites/default/files/documents/products/2024/WARA%202024%20Peak%20Demand%20by%20Subregion.pdf.

[12] WECC, *Western Assessment of Resource Adequacy 2024*, https://feature.wecc.org/wara/ [hereinafter *Western Assessment of Resource Adequacy 2024*].

[13] NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[14] *See id.* at 7.

[15] *Id.* at 160.

[16] *Id.* at 161.

[17] *Id.*

[18] EIA, *Elec. Data Browser, Net Generation for All Sectors Annually from 2019-2025, State: Colo.* (last accessed Aug. 21, 2026), www.eia.gov/electricity/data/browser/#/topic/0? agg=2,0,1&fuel=vtvp&geo=0000000000g&sec=g&freq=A&start=2019&end=2024&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0.

in Colorado is scheduled to retire according to the Energy Information Administration (EIA),[19] accounting for all but one coal-fired power plant in Colorado. In that same time frame, 620 MW of natural gas-fired generating capacity in Colorado will retire as well.[20] In 2025, intermittent wind generating capacity accounted for over 5,300 MW of Colorado's electricity generating capacity.[21]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-14, 202-26-21, and 202-26-31 continue, both in the near and long term. The availability of electricity from Craig Unit 1 will continue to be critical to maintain reliability in the WECC–Rocky Mountain region. According to the June 2026 EIA-923 Power Plant Operations Report's monthly generation data, the total net generation for Craig Unit 1 from January 2026 to June 2026 was 56,782 MWh, for an average of 9,463.6 MWh per month.[22] These generation data indicate that Craig is providing vital generation capacity to the region.

The 2025 WECC Western Assessment of Resource Adequacy notes that "the West's planned resource buildout will not keep up with anticipated load growth over the next decade, particularly in the Basin and Northwest subregions. The West could see energy shortfalls as early as 2028."[23] The assessment goes on to say that "[i]f resources are added as planned, loss of load may be limited to the Basin and Northwest subregions. However, if planned resource additions are delayed or cancelled, other subregions could also be at risk."[24] Further, the assessment highlights that 90% of planned resources over the next decade are inverter-based resources, which "continue the rapid evolution of the resource mix away from traditional dispatchable resources to more weather-

[19] EIA, *Preliminary Monthly Elec. Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of January 2026, Plant State: Colo., Technology: Conventional Steam Coal* (Jan. 2026), www.eia.gov/electricity/data/eia860m/.

[20] EIA, *Preliminary Monthly Elec. Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of June 2026, Plant State: Colo., Technology: Natural Gas Fired Combustion Turbine & Natural Gas Stream Turbine* (June 2026), www.eia.gov/electricity/data/eia860m/.

[21] EIA, *Preliminary Monthly Elec. Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generator as of June 2026, Plant State: Colo., Technology: Onshore Wind Turbine* (June. 2026), www.eia.gov/electricity/data/eia860m/.

[22] *See* EIA, *Form EIA-923 detailed data with previous form data (EIA-906/920)*, June 2026, https://www.eia.gov/electricity/data/eia923/ (choose "2026: EIA-923 June 2026").

[23] WECC, *2025 W. Assessment of Res. Adequacy*, https://feature.wecc.org/2025wara/index.html.

[24] *Id.*

dependent resources."[25] The assessment notes that "entities plan to retire 22 GW of generation over the next 10 years. The vast majority is baseload generation such as coal (7 GW), natural gas (8 GW), and nuclear (2.3 GW, Diablo Canyon's two units, in 2029 and 2030)."[26]

NERC released its 2026 State of Reliability (SOR) on June 24, 2026. In the SOR, NERC identifies worsening reliability concerns tied to large-load integration and localized operating stress. In its technical discussion of major system events, NERC states "shoulder seasons have become increasingly challenging for Bulk Power System operators to manage, resulting in several recent instances of pre-contingent load shedding."[27] The SOR also finds large load growth is increasing reliability risk and states that "data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics."[28]

Order Nos. 202-25-14, 202-26-21, and 202-26-31 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156, *"*Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[29] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[30] In the subsequent Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence [(AI)] data centers and increase in domestic manufacturing."[31]

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[25] *Id.*

[26] *Id.*

[27] NERC, *2026 State of Reliability: Tech. Assessment of 2025 Bulk Power Sys. Performance*, at 5 (June 24, 2026), https://www.nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_technical_assessment.pdf.

[28] *Id.* at vii.

[29] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[30] *Id.*

[31] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.whitehouse.gov/presidentialactions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

In addition, President Trump issued a White House Memo for the Secretary that emphasized the findings of Executive Order No. 14156, stating that "ensuring reliable coal supply chains and baseload power generation capacity is essential to the United States national defense . . . . Without sufficient coal-fired baseload power, the United States will lack the stable electricity required to support defense installations, industrial expansion, and the high-energy demands of emerging technologies, such as [AI]."[32] The President "further determine[d] that action to expand coal supply chain capacity and baseload generation availability is necessary to avert an industrial resource or critical technology item shortfall that would severely impair national defense capability."[33]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order No. 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving [AI] innovation.[34] WECC's 2025 Western Assessment of Resource Adequacy estimates that, in the WECC–Rocky Mountain region over the next decade, demand growth will be 27% and peak demand growth 23% stating that "[m]ajor drivers of demand growth in the Rocky Mountain subregion include data centers."[35]

SPP West's resource adequacy concerns were recently demonstrated during summer 2026 when SPP issued multiple Energy Emergency Alerts (EEA). On July 20, 2026, SPP West declared an EEA level 3, followed by an EEA level 2 on July 24, 2026, and an EEA level 1 on August 9, 2026.[36] SPP requested the Department to issue emergency Order Nos. 202-26-36, 202-26-37, and 202-26-37A on July 20, 2026, July 26, 2026, and August 3, 2026, respectively, which authorized SPP to dispatch specified generation resources and use backup generation resources to maintain reliability and avoid loss of firm load.

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[32] Memorandum from President Donald J. Trump to the Secretary of Energy (Apr. 20, 2026) ("Presidential Determination Pursuant to Section 303 of the Defense Production Act of 1950, as Amended, on Coal Supply Chains and Baseload Power Generation Capacity"), https://www.whitehouse.gov/presidential-actions/2026/04/presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-coal-supply-chains-and-baseload-power-generation-capacity/.

[33] *Id.*

[34] U.S. Dep't of Energy, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U. S. Elec. Grid*, at 1 (July 2025), www.energy.gov/sites/default/files/2025-11/DOE%20Final%20EO%20Report%20%28REVISED%20OCT%2027%29.pdf.

[35] *2025 W. Assessment Supplemental Info.*, W. Elec. Coordinating Council, https://feature.wecc.org/warasupplemental/index.html (last visited Sep. 16, 2026).

[36] SPP, *Summer 2026 Operating Conditions in the SPP W. Balancing Auth. Area* (June 2026), https://spp.org/documents/77689/summer%202026%20operating%20conditions%20in%20spp%20west%20baa%20report.pdf.

Pursuant to section 202(c)(4)(B) of the FPA, DOE has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[37] This statutory language constitutes a specific grant of authority to the Secretary to require that Craig Unit 1 continue to be available to operate when the Secretary has determined that such operation will best meet an emergency.

As described above, the emergency conditions resulting from increasing demand and shortage of electric energy from premature retirement of the Craig Unit 1 generation facility will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety.

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and to serve the public interest under FPA section 202(c), Craig Unit 1 shall be made available for operation through December 25, 2026.

Based on my determination of an emergency set forth above, I hereby order:

A. From September 27, 2026, Tri-State, SPP, and the co-owners shall take all measures necessary to ensure that Craig Unit 1 is available to operate to meet the emergency.[38] For the duration of this Order, SPP is directed to take every step to employ economic dispatch of Craig Unit 1 only during hours necessary to meet the emergency and to minimize costs to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Tri-State and the co-owners are directed to comply with all orders from SPP related to the availability and dispatch of Craig Unit 1.

[37] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

[38] WAPA, *Sw. Power Pool RTO Membership Initiative*, https://www.wapa.gov/about-wapa/the-source/key-topics/southwest-power-pool-membership.

B. To minimize adverse environmental impacts, this Order limits operation of Craig Unit 1 to the times and within the parameters established in paragraph A. SPP and Tri-State, in coordination with the co-owners, shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Craig Unit 1 has operated in compliance with this Order.

C. All operations of Craig Unit 1 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees, or purchase offsets or allowances for emissions that occur during the emergency conditions, or to use other geographic or temporal flexibilities available to generators.

D. By October 10, 2026, Tri-State, in coordination with the co-owners, is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Craig Unit 1 consistent with this Order. SPP, Tri-State, and the co-owners shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, as requested by the Department from time to time.

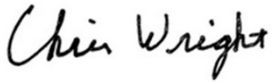
E. Tri-State and the co-owners are directed to file any tariff revisions or waivers with FERC to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Craig Unit 1 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Craig Unit 1 shall not be considered a capacity resource.

H. This Order shall be effective from September 27, 2026, through December 25, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this Friday, September 25, 2026.



Chris Wright
Secretary of Energy

cc:

Federal Energy Regulatory Commission

Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Colorado Public Utilities Commission

Chairman Eric Blank
Commissioner Megan Gilman
Commissioner Tom Plant

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit XXX: State of Colorado, The State of Colorado's Request for Rehearing, Motion to Intervene, and Stay Request (July 24, 2026)

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I. Introduction

On June 26, 2026, the Department of Energy ("Department") issued Order No. 202-26-31 ("Renewed Order")[1] pursuant to its emergency authority under Section 202(c) of the Federal Power Act ("FPA")[2] ("Section 202(c)") to continue to prevent the scheduled retirement of a coal-fired generating unit at the Craig Power Station in Moffat County, Colorado. The Renewed Order requires the availability of one coal-fired unit ("Craig Unit 1") from June 29, 2026, through September 26, 2026, thereby extending for 90 days the effect of Order No. 202-26-21 ("Second Order"),[3] which was issued on March 30, 2026, and Order No. 202-25-14 ("Original Order'),[4] which was issued on December 30, 2025. After issuing both the Original Order and the Second Order, the Department denied all prior Requests for Rehearing. Two days before issuing the Renewed Order, the Department addressed the requests for rehearing on the Original Order. The Department has made no attempt to seek comment or advice as to whether a continued extension is necessary or whether there are alternative ways to address its perceived emergency.

There is still no emergency justifying the Department's Renewed Order, and even if there were, preventing the retirement of Craig Unit 1 is not the best (or even a reasonable) way to meet the alleged emergency, and does not serve the public interest. Therefore, this Renewed Order, like the Department's Original Order and Second Order to prevent the retirement of Craig Unit 1, is illegal. The FPA limits the

[1] Exhibit KKK (Department, Order No. 2026-26-31 (June 26, 2026)).
[2] 16 U.S.C. § 824a(c).
[3] Exhibit TT (Department, Order No. 202-26-21 (March 30, 2026)).
[4] Exhibit A (Department, Order No. 202-25-14 (Dec. 30, 2025)).

use of Section 202(c) to addressing specific, imminent capacity shortfalls resulting from unexpected outages, natural disasters, extreme weather, and similar circumstances. Here, the Department has declared an emergency due to "a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes" in the Western Electricity Coordinating Council ("WECC")-Rocky Mountain assessment area.[5] But, like the Original and Second Orders, the Renewed Order's emergency determination cannot stand against even the mildest scrutiny.

As Colorado demonstrated in its Request for Rehearing, Motion to Intervene, and Stay Request ("Original Request")[6] of the Original Order and its Request for Rehearing, Motion to Intervene, and Stay Request ("Second Request")[7] of the Second Order there is no energy "emergency" as defined by Section 202(c) in the WECC-Rocky Mountain assessment area or in Colorado. Rather, the Unit's owners and their respective state utility commissions have been planning for Craig Unit 1's retirement for the last decade.[8] These comprehensive planning processes have ensured that there are reliable and affordable resources available to meet the energy needs in the areas served by Craig Unit 1, such that its long-planned retirement does not create an emergency.

[5] Exhibit TT. This is a change from the Original Order, which declared an energy emergency in the WECC-Northwest assessment area. Exhibit A.
[6] Exhibit CCC (State of Colorado, The State of Colorado's Request for Rehearing, Motion to Intervene, and Stay Request (Jan. 28, 2026)).
[7] Exhibit LLL (State of Colorado, The State of Colorado's Request for Rehearing, Motion to Intervene, and Stay Request (April 28, 2026)).
[8] *See, e.g.*, Exhibit C (Declaration of Erin O'Neil (July 23, 2026)), ¶ 33.

The Department's illegal use of its Section 202(c) authority to require the continued availability of Craig Unit 1 for an additional 90 days, unsupported by any evidence of an imminent energy emergency, will result in unnecessary operational and maintenance costs that will be imposed on ratepayers in Colorado, including the State of Colorado as a utility customer, and potentially other states. Continued operation of Craig Unit 1 pursuant to the Renewed Order will also emit needless pollution into Colorado and its neighboring states, which the Department failed to meaningfully consider or address, as it was required to do. The Renewed Order, like the Original and Second Orders, illegally intrudes on the authority of the states to ensure the resource adequacy of their electric grids and to dictate energy policy within their borders, and improperly attempts to impose the administration's policy preferences on state ratepayers.

Pursuant to Section 313*l* of the FPA,[9] the Colorado Attorney General, on behalf of the State of Colorado, timely submits this Request for Rehearing, Motion to Intervene, and Stay Request ("Request") seeking rehearing of the Renewed Order. The Department should grant rehearing and rescind the Renewed Order because it is an unlawful abuse of the Department's emergency authority, is unsupported by evidence showing a true emergency, and is arbitrary and capricious.

[9] 16 U.S.C. § 825*l*.

II. Motion To Intervene

The State of Colorado moves to intervene in the proceeding initiated by the Renewed Order and become a party for purposes of Section 313*l* of the FPA.[10] The State of Colorado is aggrieved by the Renewed Order in several ways.

First, households and businesses in Colorado have and will be required to pay higher electricity bills because of the Renewed Order.[11] Through a carefully planned process driven by economic considerations, the owners of Craig Unit 1 planned to retire the Unit and replace it with more cost-effective facilities.[12] By ordering the continued operation of Craig Unit 1, the Renewed Order guarantees that Tri-State Generation and Transmission Association, Inc. ("Tri-State"), PacifiCorp, Platte River Power Authority ("PRPA"), Salt River Project, and Public Service Company of Colorado ("Public Service") (together, "Craig Unit 1 Owners"), will incur higher costs to serve their members and customers, which they will then likely seek to pass on to their electricity consumers, including rural customers in Colorado.[13] Tri-State has already had to pass the cost of repairing Craig Unit 1 on to its customers,[14] which include the State.

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[10] *Id.*

[11] Exhibit D (Declaration of Joseph Pereira (July 22, 2026)). Because the Order directs the Craig Unit 1 Owners to seek cost recovery the possibility of increased rates is a foreseeable harm for Colorado. Exhibit A, ¶ E. Tri-State and PRPA have confirmed that their "members and customers must pay" the costs of DOE's Original Order. However, Colorado reserves all rights to dispute that costs incurred based on the Order are appropriate.

[12] Tri-State, *Reliable, Lowest-Cost, Reduced Emissions Preferred Portfolio Focus of Tri-State Resource Plan Filing* (Apr. 11, 2025) (last visited Apr. 24, 2026).

[13] Exhibit D, ¶¶ 10, 16.

[14] Exhibit UU (Tri-State, *Request for Clarification and for Rehearing of Tri-State Generation and Transmission Association and Platte River Power Authority* (Jan. 29, 2026)); Exhibit MMM (Tri-State, *Request for Clarification and for Rehearing of Tri-State Generation and Transmission Association and Platte River Power Authority* (April 29, 2026)).

Second, the Craig Unit 1 Owners determined that it is prudent to retire Craig Unit 1 and replace it with more reliable and cost-effective resources. And the Colorado Public Utilities Commission ("CoPUC") determined that retiring Craig Unit 1 will not affect Tri-State's resource adequacy.[15] By continuing to delay the retirement of a 45-year-old coal-fired unit, the Department is causing Colorado's electric customers to be served by a more costly and less reliable and resilient electric grid. Instead of continuing to invest in and develop more reliable resources as planned, the Craig Unit 1 Owners will have to dedicate resources to repair and maintain a coal plant that is less reliable and more costly than other generation resources. For example, due to limited transmission capacity, Craig Unit 1's continued operation will prevent the use of solar electricity generated by its new solar farm in Moffat County.[16]

Third, Colorado will suffer environmental harms from Craig Unit 1's operation pursuant to the Renewed Order. Craig Unit 1 is a significant source of particulate matter ("PM"), nitrogen oxides ("NOx"), sulfur dioxide ("SOx"), carbon monoxide ("CO"), mercury, hazardous air pollutants ("HAPs"), and greenhouse gas ("GHG") emissions, and its scheduled retirement would have resulted in significant emissions reductions.[17] Operating Craig Unit 1 beyond its planned retirement date will increase the amount of pollution emitted in Colorado, harming the environment, public health, and welfare, as well as Colorado's ability to comply with other federal and State

[15] *See e.g.*, Exhibit E (CoPUC, Decision No. C25-0612, issued on August 26, 2025, in Proceeding No. 23A-0585E), at ¶ 116; CoPUC, Decision No. R22-0191, issued on March 28, 2022, in Proceeding No. 20A-0528E.
[16] Exhibit UU.
[17] Exhibit B (Declaration of Josh Korth (July 22, 2026)), ¶¶ 18-23.

environmental laws.[18] The Renewed Order does not make a meaningful attempt to minimize or mitigate the emissions impact of continued operation of Craig Unit 1 as required.

Finally, State authority over generation resources has been a bedrock principle of the FPA for nearly a century. Federal intrusion in this traditional sphere of state control is permitted only in a true emergency and only with specific procedures that the Department did not follow when issuing the Renewed Order. Colorado's sovereign interest in seeing its State laws followed in an area reserved to State sovereign authority further warrants the State's intervention.

III. Background

Like the Original and Second Orders, the Renewed Order makes several unfounded claims about Colorado's energy resource mix, expected increases in energy demand in the region, and the resulting need for continued availability of Craig Unit 1 to address an alleged energy emergency.

A. Craig Unit 1 is owned by several utilities with specific service areas.

Craig Unit 1, along with Craig Units 2 and 3, comprise Craig Station, a 1,285 megawatt ("MW"), generating facility in Moffat County, CO.[19] Craig Units 1 and 2, also known as the Yampa Project, are operated solely by Tri-State but are co-owned by Craig Unit 1 Owners. Craig Unit 1 has a 427 MW capacity and began operating in 1980,

[18] *Id.*, ¶¶ 20-27.
[19] Tri-State, *Craig Station Unit 2 owners announce retirement date of Sept. 30, 2028* (July 8, 2020), (last visited Jan. 26, 2026); Exhibit F (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-2, (Tri-State, 2020 IRP/ERP, Public (Dec. 1, 2020)), at 182.

making it over 45-years-old.[20] Craig Unit 1 was approved to retire on December 31, 2025. Craig Unit 2, which has a 410 MW capacity, has an approved retirement date of September 30, 2028, and Craig Unit 3, which is solely owned and operated by Tri-State and has a 448 MW capacity, will retire by 2030.[21]

Tri-State is a wholesale electric generation and transmission cooperative association with members located across Colorado, Nebraska, New Mexico, and Wyoming. Tri-State is a non-profit corporation and is owned and governed by its members through a Board of Directors.[22] Tri-State's board is responsible for approving rates, major capital investments, and resource planning decisions.[23] These resource planning decisions must then be approved by the CoPUC. Tri-State's ownership share of Craig Unit 1 is 24%, and Tri-State therefore is entitled to 102.5 MW out of Craig Unit 1's 427 MW capacity.[24] It is Colorado's understanding that within Tri-State's service territory, only Colorado and Wyoming receive energy from Craig Unit 1. PRPA and Public Service are the two other Colorado-based utilities with an ownership stake in Craig Unit 1. PRPA is a non-profit community-owned power generation and transmission utility that provides energy to Estes Park, Fort Collins, Longmont, and Loveland, Colorado.[25] PRPA has an 18% ownership share of Craig Unit 1 and is

[20] Global Energy Monitor, a project of the Sierra Club, *Craig Station* (last updated Jan. 5, 2026) (last visited Jan. 26, 2026); Exhibit F, at 182.
[21] Tri-State, *Craig Station Unit 2 owners announce retirement date of Sept. 30, 2028* (July 8, 2020); Exhibit F, at 182; Exhibit G (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-1 (Tri-State, Responsible Energy Plan ("Responsible Energy Plan") (Jan. 2020)), at 3.
[22] Exhibit JJ (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Proceeding 20A-0528E), at 13:8-13.
[23] *Id.*, at 13:16-22.
[24] Exhibit J (CoPUC, 120 Day ERP Implementation Report, Public, filed on April 11, 2025, in Proceeding No. 23A-0585E).
[25] Exhibit EE (PRPA, *2024 Integrated Resource Plan* (Apr. 2023)).

therefore entitled to 77 MW of Craig Unit 1's capacity.[26] Public Service is a subsidiary of Xcel Energy, Inc., and is the largest gas and electric provider in Colorado. However, Public Service has the smallest ownership stake in Craig Unit 1, owning 9% (38.4 MW of Craig Unit 1's total capacity).[27]

The Salt River Project and PacifiCorp are the two non-Colorado owners of Craig Unit 1. The Salt River Project is a non-profit organization that provides power in central Arizona.[28] The Salt River Project owns 29% of Craig Unit 1 (124 MW of Craig Unit 1's total capacity).[29] However, the Salt River Project did not receive energy from Craig Unit 1 directly and instead traded for it through the Western Area Power Administration ("WAPA") until April 1, 2026 when that contract expired. PacifiCorp is based in Oregon but serves customers in Oregon, Washington, California, Utah, Idaho, and Wyoming. PacifiCorp has a 19% ownership of Craig Unit 1 (81 MW of Craig Unit 1's total capacity). Neither utility's service territory is in the WECC-Rocky Mountain assessment area.

B. The Craig Unit 1 Owners decided to retire Craig Unit 1 ten years ago and included the retirement in their resource plans.

In 2016, the Craig Unit 1 Owners voluntarily decided to retire Craig Unit 1 by December 31, 2025, based on "the [S]tate and federal regulatory environment for coal-based generation, current and forecasted market conditions, the significant costs to install additional emissions controls, and the best interests of electric

[26] Exhibit FF (PRPA, *Craig Units 1&2 (Yampa Project)* (2026)).
[27] Global Energy Monitor, *Craig Station*.
[28] Exhibit H (Salt River Project, *2023 Integrated Systems Plan*), at 6.
[29] *Id.*, at 27.

consumers."[30] The Craig Unit 1 Owners agreed to proposed revisions to Air Quality Control Commission ("Air Commission") Regulation No. 23 and Colorado's Regional Haze State Implementation Plan ("SIP") to include the December 31, 2025 retirement date.[31] The U.S. Environmental Protection Agency ("EPA") approved Craig Unit 1's retirement date on July 5, 2018.[32] Since 2016, the Craig Unit 1 Owners have incorporated the planned closure of the unit as an assumption in all electric resource planning proceedings, reports, decisions and modeling.[33] None of these processes or reports conclude that resource adequacy or reliability would be threatened by the unit's retirement.

Tri-State's resource plans are overseen by the CoPUC. The CoPUC reviewed Tri-State's load forecasts, resource needs, and planned resource acquisitions, all of which included the retirement of Craig Unit 1 by December 31, 2025 as an underlying assumption, as part of Tri-State's 2020 ERP and most recently its 2023 ERP for planning years 2026-2031.[34] As recently as August 2025, the CoPUC found that "Craig Unit 1 is not required for reliability or resource adequacy purposes based on the record in this ERP. Every portfolio that Tri-State modeled for its most recent ERP

[30] Tri-State, *Craig Station Owners, Regulators and Environmental Groups Reach Agreement on Proposed Revisions to Colorado Regional Haze Plan* (Sep. 1, 2016).
[31] *See id.*; 5 Colo. Code Reg. § 1001-27, Part A, Section IV.D.1 (2025).
[32] Air Plan Partial Approval and Partial Disapproval; Colorado; Regional Haze Plan for the Second Implementation Period, 83 Fed. Reg. 31332 (July 5, 2018).
[33] Tri-State, *Craig Station Owners Agreement* (Sep. 1, 2016); *e.g.*, CoPUC, *Tri-State, ERP Annual Progress Report, Revised*, filed on June 2, 2017, in Proceeding No. 15M-0852E, at 16; CoPUC, ERP for Annual Progress Report, filed on October 31, 2018, in Proceeding No. 15M-0852E, at 17; CoPUC, ERP Annual Progress Report, filed on December 10, 2019, in Proceeding No. 15M-0852E, at 22.
[34] Exhibit F, at 31; CoPUC, 150-Day Report, Public, filed on February 13, 2023, in Proceeding No. 20A-0528E, at 28; Exhibit X (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 (Tri-State, 2023 ERP Phase I, Rev. 2 (Apr. 22, 2024)), at 19, 21, 32, 44, 55, 66; Exhibit J, at 21, 32, 43, 54, 64, 75.

assumes that Craig Unit 1 retires at the end of 2025 . . . every portfolio meets all reliability metrics and is reliable."[35] The CoPUC further found that Tri-State's resource plan—including the retirement of Craig Unit 1—is resource diverse and cost effective, ensuring energy security, economic prosperity, and environmental protection. Tri-State reaffirmed on January 23, 2026, that the Craig Unit 1 retirement "has informed operational and maintenance decisions, and Tri-State has planned for adequate resources to maintain reliability on its system following the unit's retirement."[36] And the Resource Adequacy Report filed by Tri-State on March 17, 2026, did not present any resource adequacy or reliability issues, and continues to project no capacity shortfalls through 2035.[37] PRPA, which conducts its own integrated resource planning process, also has sufficient resources without Craig Unit 1. In fact, both PRPA and Tri-State challenged the Original and Second Orders because they do not need Craig Unit 1 and do not wish to unnecessarily incur costs to operate it.[38]

The other Craig Unit 1 Owners are subject to similar oversight by their state utility commissions. As part of their respective state-approved resource plans, Salt River Project and PacifiCorp have confirmed there are no resource adequacy concerns in their respective states associated with the retirement of Craig Unit 1.

[35] Exhibit E, ¶ 116.
[36] Tri-State, *Tri-State makes Craig Generating Station Unit 1 available to operate in compliance with DOE emergency order* (Jan. 23, 2026).
[37] Exhibit VV (CoPUC, Tri-State, Notice of 2026 Resource Adequacy Annual Report, filed on March 17, 2026, in Proceeding No. 26M-0028E).
[38] Exhibit UU; Exhibit MMM.

Underscoring the lack of need for Craig Unit 1, the unit suffered an outage on December 19, 2025 due to a mechanical failure of a valve.[39] Absent the Original Order, it is unlikely the Owners would have expended new resources to repair the aging unit given that they were not expecting to use it to generate energy after December 31st. Tri-State and the co-owners paid for the repair of Craig Unit 1 pursuant to the Original Order, and this cost has been passed along to Tri-State's and PRPA's,[40] and likely the other utilities', customers. Craig Unit 1 was in a forced outage until its repairs were completed around mid-January,[41] and it was then available to operate, but did not operate, for the remainder of the period of the Original Order. It is Colorado's understanding that at the time of filing this Request, Craig Unit 1 has again been put into a forced outage.

C. Federal Energy Regulatory Commission ("FERC") and its designated entities also oversee resource planning decisions for Craig Station to ensure reliability.

The structure of FERC's management of the bulk power system is important to understand various studies and reports as they relate to the claimed emergency identified in the Renewed Order. The reliability and resource adequacy of the electric power system in states that are not within Independent System Operators ("ISOs") or Regional Transmission Organizations ("RTOs") are typically managed by individual utilities, which are often vertically integrated, meaning they handle generation, transmission, and distribution of electricity within their service areas, and are

[39] Exhibit QQ (Tri-State, *U.S. DOE Orders Tri-State to Keep Craig Generating Station Unit Operating for Next 90 Days* (Dec. 31, 2025)); *see also* Exhibit B, ¶ 11; Exhibit D, ¶ 15.
[40] Exhibit UU.
[41] Tri-State, *Tri-State makes Craig Generating Station Unit 1 available to operate in compliance with DOE emergency order* (Jan. 23, 2026).

typically overseen by state public utilities commissions or a similar state entity.[42] These utilities are also subject to reliability oversight by FERC and several balancing authorities, in addition to being subject to their state resource planning and reliability requirements. Utilities in an RTO, which now includes Tri-State and PRPA,[43] are subject to additional frameworks and oversight. These related processes are designed to govern long-term planning and resource adequacy, and are reserved to FERC, RTOs, and the states under the FPA.[44]

FERC oversees the reliability of the bulk power system, which is the network of generation, transmission, and distribution system components across the United States, by reviewing, approving, and enforcing mandatory reliability standards developed by the North American Electric Reliability Corporation ("NERC").[45] FERC designated NERC as the Electric Reliability Organization ("ERO") for the mainland United States in 2006 pursuant to the Energy Policy Act of 2005.[46] NERC is a non-profit international regulatory authority that assures the reliability of North America's bulk power system by creating reliability standards, approved by FERC, that are legally enforceable and include training and communications requirements, and emergency back up plans.[47] These standards apply to all users, owners, and operators of the continental United States' bulk power system.[48] NERC also annually analyzes seasonal

[42] FERC, *Energy Markets* (Aug. 18, 2025) (last visited Jan. 26, 2026).
[43] Tri-State and PRPA are part of the Southwest Power Pool ("SPP")'s RTO expansion in the Western Interconnection, which began operations on April 1, 2026.
[44] *See* 16 U.S.C. § 824(b)(1); 16 U.S.C. § 824a(b).
[45] FERC, *Reliability Explainer* (Aug. 16, 2023) (last visited Jan. 26, 2026).
[46] *See id.*; 16 U.S.C. § 824*o*(a)(2); N. Am. Elec. Reliab. Corp., 116 FERC ¶ 61,062 (2006), at 3, order on reh'g & compliance, 117 FERC ¶ 61,126 (2006).
[47] FERC, *Reliability Explainer* (Aug. 16, 2023).
[48] 16 U.S.C. § 824o(b)(1).

and long-term reliability of the bulk power system and assesses risk by region using a three-tiered system.[49]

NERC is permitted to delegate authority to regional entities for the purpose of proposing and enforcing reliability standards.[50] NERC therefore divides the North American bulk power system into six regional entities to which it has delegated authority. One of these regional entities is WECC, which covers most of the Western United States, including all of the states served by Craig Unit 1.[51] WECC is a non-profit organization that assures a reliable electric system in the Western Interconnection, a region that covers the Pacific Ocean to the Rocky Mountain states.[52] All of the Craig Unit 1 Owners are members of WECC.[53]

WECC identifies and registers the Reliability Coordinators and balancing authorities that are responsible for maintaining operating conditions under NERC's reliability standards within its region.[54] Reliability Coordinators are the highest level of authority under NERC. They are responsible for the operation of the bulk electric system and have the operating tools, procedures, and authority to prevent or mitigate emergency operating situations.[55] Balancing authorities ensure that power system demand and supply are balanced, manage transfers of electricity and use economic dispatch to optimize the use of generating units and minimize real-time costs, and

[49] *See* 18 C.F.R. § 39.11.
[50] *id.* § 39.8.
[51] *See* Fully Executed North American Electric Reliability Corp., *Amended And Restated Delegation Agreement Between NAERC And WECC* (2021 FERC Revisions – Clean) (Jan. 1, 2021).
[52] EPA, *U.S. Grid Regions* (Nov. 24, 2025).
[53] WECC, *Membership* (2026).
[54] Department, *Learning Series: Energy Security & Resilience*; WECC, *Registration and Certification* (2026).
[55] NERC, *NERCipedia: Reliability Coordinator* (2024).

maintain operating conditions under NERC reliability standards.[56] As of April 1, 2026, Southwest Power Pool, Inc. ("SPP") is the Reliability Coordinator for Public Service, Tri-State, and PRPA, and the Balancing Authority for Tri-State and PRPA.[57]

In addition to this structure, FERC has encouraged the formation of nonprofit entities known as ISOs and RTOs.[58] FERC concluded that the use of ISOs and RTOs could address operational and reliability issues, improve transmission grid management, improve market performance, and facilitate lighter regulation.[59] RTOs and ISOs work with FERC and the states to ensure resource adequacy by imposing resource adequacy requirements on member utilities and monitoring the day to day operations of the grid.[60]

In December 2025, the CoPUC determined that it is in the public interest for Tri-State to join the SPP RTO as part of SPP's western expansion in April of 2026.[61] Both Tri-State and PRPA joined the SPP RTO on April 1, 2026.[62] The SPP RTO is a "nonprofit corporation mandated by [FERC] to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale electricity prices on behalf of its members."[63] The SPP RTO runs an Integrated Marketplace, which includes, among other things, a real time balancing market and a day ahead market.[64]

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[56] Department, *Learning Series: Energy Security & Resilience*.
[57] SPP, *2026 RTOE SWPW Transition Plan – Market Participant* (Version 2.2, Mar. 19,2026).
[58] Regional Transmission Organizations, 65 Fed. Reg. 810, 811 (Jan. 6, 2000); Promoting Wholesale Competition Through Open Access Non-Discriminatory Transm. Servs. by Pub. Utils. and Recovery of Stranded Costs by Pub. Utils. and Transm. Utils., 61 Fed. Reg. 21540-01, 21542 (May 10, 1996).
[59] 65 Fed. Reg. at 811.
[60] Klass A., *The President and the Power Grid*, Mich. L. Rev. Online (forthcoming Apr. 2026).
[61] CoPUC, Decision No. C25-0906, issued on December 16, 2025, in Proceeding No. 25A-0266E, ¶ 2.
[62] SPP, *Order Accepting Tariff Revisions, Subject to Condition*, 190 FERC ¶ 61,169 (Mar. 20, 2025)
[63] SPP, *About Us* (last visited Apl. 24, 2026).
[64] *Id.* at *SPP Portal*.

SPP RTO's western expansion includes parts of Colorado, Wyoming, and several other states, but its footprint does not align exactly with either the WECC-Rocky Mountain region or the WECC-Basin region.[65]

The Renewed Order states, without support, that the WECC-Rocky Mountain Assessment area is experiencing an energy emergency based on the 2025 WECC Western Assessment of Resource Adequacy ("2025 WECC Assessment") and NERC's 2026 Summer Reliability Assessment ("2026 SRA").[66] But those materials do not find that the WECC-Rocky Mountain Assessment Area is experiencing an energy emergency, and neither NERC, WECC and its designees, nor SPP have made a similar emergency determination. The Renewed Order cites to the 2025 WECC Assessment's statements that the West could see energy shortfalls beginning in 2028, that planned resources are largely inverter-based resources, and that entities plan to retire generation over the next ten years.[67] The Renewed Order also cites to the 2025 WECC Assessment's statement that the Basin and Northwest subregions planned resource buildout will not keep up with anticipated load growth over the next decade, even though the Renewed Order only declares an emergency in the Rocky Mountain subregion.[68]

Next, the Renewed Order cites the 2026 SRA's statement that wildfires combined with extreme heat pose the greatest reliability risk scenario for the Rocky Mountains.[69] However, the Renewed Order itself notes that the 2026 SRA found that the WECC-Rocky Mountain region's anticipated reserve margins will remain above the

[65] Compare *id.* at *RTO Expansion* to Exhibit WW (NERC, *Long-Term Reliability Assessment* (Jan. 2026).
[66] Exhibit KKK at 3-5.
[67] *See id.*, at 3-4.
[68] *Id.*
[69] Exhibit NNN (2026 NERC Summer Resource Adequacy Report).

reference margin level for the 2026 summer assessment period, and therefore the WECC-Rocky Mountain region is at "normal risk".[70] NERC defines an assessment area as "normal risk" when its resource adequacy criteria are met, and it is expected to have sufficient resources for extreme conditions.[71] A region cannot have a better designation than "normal risk" in a SRA. The summer assessment period is June – September, which covers the duration of the Renewed Order.[72]

Even if these reports had included credible evidence of an emergency in the Rocky Mountain assessment area, the 2025 WECC Assessment does not address short-term, imminent reliability issues, and neither the 2026 SRA nor the 2025 WECC Assessment accounts for the westward expansion of SPP's RTO and the resulting mismatch between SPP West and WECC-Rocky Mountain's footprints. Therefore, these reports cannot support a decision by the Department to keep one power plant open in the name of the Department's alleged region-wide emergency.

Thus, the assessments covering the areas served by Craig Unit 1 for both the 90-day term of the Renewed Order and beyond do not conclude that there is an energy shortfall or a reliability concern. Yet, the Department has re-issued a Section 202(c) Order declaring that an emergency exists within the WECC-Rocky Mountain assessment area "due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes."[73] The Renewed Order requires the

[70] Exhibit KKK, at 3.
[71] Exhibit NNN, at 2.
[72] *Id.* at 1.
[73] Exhibit KKK, at 1.

Craig Unit 1 Owners to ensure that the unit is available to operate for the next 90 days and directs SPP to employ economic dispatch of Craig Unit 1.[74]

D. The Renewed Order is part of the broader federal efforts to support the coal industry.

On January 20, 2025, President Trump issued Executive Order 14156, "Declaring a National Energy Emergency."[75] That declaration did not provide any factual support for its assertion that the country was in the grips of an electricity emergency. In fact, U.S. energy production is at an all-time high and continues to grow.[76] Although the President recently extended the energy emergency declaration for an additional year, he did not cite any new evidence to justify the supposed emergency.[77]

Setting the stage for the Department's plan to use Section 202(c) orders to promote the administration's policy preferences for the nation's energy mix, on April 14, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid."[78] This Executive Order directed the Department to streamline and expedite processes for issuing emergency orders under Section 202(c). It also ordered the preparation of a methodology to help identify areas with inadequate reserve margins and directed the use of Section 202(c) orders to prevent certain generation resources from leaving the bulk power system.[79]

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[74] *Id.*
[75] Declaring a National Energy Emergency, 90 Fed. Reg. 8433 (Jan. 20, 2025).
[76] Zaretskaya, V., *The United States was the world's largest liquified natural gas exporter in 2023* (Apr. 1, 2024); U.S. Energy Info. Admin., *U.S. Exports of Crude Oil* (Dec. 31, 2025); U.S. Energy Info. Admin., *U.S. Energy Facts Explained: Imports & Exports* (July 15, 2024).
[77] Continuation of the National Emergency With Respect to Energy, 91 Fed. Reg. 1667 (Jan. 12, 2026).
[78] Exec. Order 14262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521 (Apr. 14, 2025).
[79] *Id.*

Pursuant to this Executive Order, the Department published its report titled *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* ("Resource Adequacy Report" or "Report"),[80] on July 7, 2025.

Colorado and several other states filed a request for rehearing of the Resource Adequacy Report that pointed out the Report's many analytical errors, including flawed and unexplained assumptions for load growth projections and resource retirements and additions.[81] The Department itself acknowledges in the Report that the agency is not equipped to analyze resource adequacy, stating that its own analysis "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[82] Thus, despite issuing a Report intended to guide its use of Section 202(c) authority, the Department does not have the ability to discern whether there is an energy emergency at the regional level.

Nevertheless, the Department proceeded to issue numerous orders under Section 202(c) in 2025 to prevent the retirement of several fossil fuel-fired power plants across the country. In May 2025, the Department issued orders preventing two fossil-fuel generation facilities in Michigan and Pennsylvania from retiring as planned. Both orders failed to identify an imminent energy emergency justifying the units'

[80] Exhibit M (Department, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (July 2025)).
[81] Exhibit N (Motion to Intervene and Protective Request for Rehearing by the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York, filed on August 6, 2025 with the Department).
[82] Exhibit M, at 2.

continued operation and instead cited only generalized concerns about resource adequacy.[83] The Department has now re-issued both orders for the fifth time.[84]

In December 2025, four additional fossil fuel-fired generation facilities were scheduled to retire, and the Department issued orders requiring their continued availability. In addition to the Renewed Order at issue in this proceeding, the Department ordered that units in Washington and Indiana remain available to operate, and the Department has now re-issued all four of those orders for the third time.[85] Most recently, the Department issued a Section 202(c) order to prevent a Florida power plant from retiring in June 2026.[86] Like the Renewed Order, each of these other Section 202(c) orders failed to support their emergency determinations with evidence of a specific, imminent energy shortfall or other circumstances that qualify as an emergency under Section 202(c).

[83] Exhibit O (Department, Order No. 202-25-3 ("Campbell Order") (May 23, 2025)); Exhibit P (Department, Order 202-25-4 ("Eddystone Order") (May 30, 2025)).
[84] *See* Exhibit I (Department, Order No. 202-25-7 (Aug. 20, 2025") ("Aug. Campbell Extension")); Exhibit U (Department, Order No. 202-25-9 (Nov. 18, 2025) ("Nov. Campbell Extension"); Exhibit V (Department, Order No. 202-25-8 (Aug. 28, 2025) ("Aug. Eddystone Extension")); Exhibit PP (Department, Order No. 202-25-10 (Nov. 25, 2025) ("Nov. Eddystone Extension")); Exhibit XX (Department, Order No. 202-26-16 (Feb. 17, 2026)) ("Feb 2026 Campbell Extension"); Exhibit YY (Department, Order No. 202-26-17 (Feb. 23, 2026)) ("Feb 2026 Eddystone Extension"); Exhibit OOO (Department, Order No. 202-26-22 (May 19, 2026))("May 2026 Campbell Extension"); Exhibit PPP (Department, Order No. 202-26-24 (May 21, 2026)) ("May 2026 Eddystone Extension").
[85] Exhibit Q (Department, Order No. 202-25-11 (Dec. 16, 2025) ("Centralia Order")); Exhibit S (Department, Order No. 202-25-12 (Dec. 23, 2025) ("Schahfer Order")); Exhibit R (Department, Order No. 202-25-13 (Dec. 23, 2025) ("Culley Order")); Exhibit ZZ (Department, Order No. 202-26-18 (Mar. 16, 2026)) ("March 2026 Centralia Extension"); Exhibit AAA (Department, Order No. 202-26-19 (Mar. 23, 2026)) ("March 2026 Schahfer Extension"); Exhibit BBB (Department, Order No. 202-26-19 (Mar. 23, 2026)) ("March 2026 Culley Extension"); Exhibit QQQ (Department, Order No. 202-26-28 (June 12, 2026) ("June 2026 Centralia Extension"); Exhibit RRR (Department, Order No. 202-26-29 (June 18, 2026) ("June 2026 Schahfer Extension")); Exhibit SSS (Department, Order No. 202-26-30(June 18, 2026) ("June 2026 Culley Extension")).
[86] Exhibit TTT (Department Order No. 202-26-26 (June 4, 2026) ("Stanton Order").

IV. Statement of Issues and Specifications of Error

The State of Colorado submits the following statement of issues and specifications of error:

1. The Renewed Order is contrary to law because Section 202(c) only authorizes the Department to respond to specific, imminent, unexpected, and temporary events, while the Renewed Order addresses long-term resource adequacy concerns. The statutory text, legislative history, judicial construction, and the Department's regulations all confirm that an emergency must be specific, imminent, unexpected, and temporary. 16 U.S.C. § 824a(c); *Richmond Power & Light of City of Richmond, Ind. v. FERC*, 574 F.2d 610 (D.C. Cir. 1978); S. Rep. No. 74 621, 74th Cong., 1st Sess. (1935); 16 U.S.C. § 824a(a) & (b); *Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232 (8th Cir. 1970).

2. The Renewed Order is contrary to law because it exceeds the Department's statutory authority by preventing the long-planned retirement of Craig Unit 1. Section 201(b) of the FPA reserves decisions about plant retirement dates to the states, and Section 202(c) does not vest the Department with general regulatory authority over resource adequacy. By abusing a statute meant only for emergencies, the Renewed Order intrudes on authority reserved to states and to other federal regulators to regulate resource adequacy. 16 U.S.C. §824(a); *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009); *see also Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 155 (2016); *Devon Power LLC et al.*, 109 FERC ¶ 61,154, P 47 (2004).

3. The Renewed Order is contrary to law because it fails to present substantial evidence for its emergency determination and ignores critical facts. None of the materials cited in the Renewed Order provide evidence of an emergency in the WECC-Rocky Mountain assessment area, and the Renewed Order ignores critical facts, including the findings in its own Resource Adequacy Report, NERC's findings, and State and utility analyses. *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983); *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962); *Chritton v. National Transportation Safety Board*, 888 F.2d 854, 856 (D.C. App. 1989); *Richmond Power & Light of City of Richmond, Ind. v. FERC*, 574 F.2d 610 (D.C. Cir. 1978); S. Rep. No. 74-621 (1935); 16 U.S.C. § 824a(a) & (b); *Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232 (8th Cir. 1970); *Emera Maine v. FERC*, 854 F.3d 9, 22 (D.C. Cir. 2017); *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

4. The Renewed Order is arbitrary and capricious because it requires generation that does not best meet the claimed emergency. 16 U.S.C. § 824a(c)(1); *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208 (2009); *Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1 (2020); *Motor Vehicle Mfrs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983); 10 C.F.R. § 205.371.

5. The Renewed Order's terms fail to comply with Sections 202(c)(2) and 202(c)(4)(b) of the FPA, and Section 103(b) of the Department Organization Act. 16 USC § 824a(c)(1); 16 U.S.C. § 824a(c)(2); 42 U.S.C. § 7113; *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009); *see also, e.g., Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 155 (2016).

6. The Renewed Order is arbitrary and capricious because it is designed to support the federal administration's policy goal of supporting the coal industry. *Dep't of Commerce v. New York*, 588 U.S. at 782; *Level the Playing Field v. FEC*, 961 F.3d 462, 464 (D.C. Cir. 2020) (quoting *Hagelin v. FEC*, 411 F.3d 237, 242 (D.C. Cir. 2005)).

7. The Renewed Order violates the National Environmental Policy Act ("NEPA") because it fails to assess the environmental consequences of a major federal action significantly affecting the human environment. 42 U.S.C. § 4321, *et seq.*; 10 CFR § 1021.103.

V. Request For Rehearing

The Department must grant rehearing and rescind the Renewed Order because it suffers from numerous legal and factual deficiencies. Ignoring the legal standards that constrain the exercise of emergency authority under Section 202(c), and acting in disregard of the facts, the Renewed Order improperly impinges on state authority over resource planning decisions, fails to present substantial evidence of an emergency, imposes unreasonable and unnecessary costs, fails to include required provisions to minimize environmental harms, and advances the administration's preferred energy source with no reasonable basis. For these reasons, the Renewed Order is contrary to law, arbitrary and capricious, and unsupported by substantial evidence. The Department should withdraw it. To the extent the Department intends

to rely on the facts and arguments presented in the Original or Second Orders to substantiate an emergency during the period of the Renewed Order, the arguments of the State of Colorado in its Original Request of the Original Order and Second Request are incorporated herein.[87]

A. The Renewed Order is contrary to law because it improperly expands the use of Section 202(c)'s emergency authority beyond the limited scope set forth in the FPA.

Section 202(c) authorizes the Department to command action from a utility unconstrained by many of the core procedural safeguards, jurisdictional boundaries, and substantive limitations normally imposed by the FPA.[88] This power far exceeds the Department's normal authority, and is therefore restricted to the extraordinary and limited circumstances set forth in the statute.[89] The FPA's statutory text and structure, along with the Department's regulations, historic practice, and case law interpreting the FPA all make clear that any such event, including a "shortage of electric energy" or the "demand for electric energy" must be one that constitutes a bona fide "emergency"—*i.e.*, a specific, imminent, unexpected and temporary event. The Renewed Order exceeds the Department's authority because those extraordinary and limited circumstances do not exist here, and the Department is instead attempting to use the Renewed Order to regulate long-term resource adequacy, which is expressly reserved to the states and FERC.

[87] Exhibit CCC; Exhibit LLL.
[88] *See* 16 U.S.C. § 824a(c).
[89] *Id.* ("[d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes . . .").

i. The language, history and structure of Section 202(c) limit the Department to addressing specific, imminent, unexpected and temporary supply shortfalls.

Section 202(c)'s text authorizes the Department to act only upon an "emergency."[90] The statute itself does not define "emergency."[91] At the time Section 202(c) was enacted, "emergency" was defined as a "sudden or unexpected appearance or occurrence . . . An unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency."[92] Contemporary dictionaries likewise define "emergency" as "an unforeseen combination of circumstances or the resulting state that calls for immediate action," or an "urgent need for assistance or relief."[93]

The remainder of Section 202(c)'s plain language also underscores the urgency and immediacy inherent in the word "emergency." The text's use of the present tense underscores its focus on imminent and certain shortfalls, empowering the Department to act only where "an emergency exists."[94] That near-term focus, along with the fact that this Section 202(c) authority is "temporary" authority,[95] precludes use of Section 202(c) to pursue long-term policy goals such as preference for a

[90] *Id.*
[91] Although emergency is not defined, the statute does indicate that an emergency includes "the continuance of any war in which the United States is engaged." 16 U.S.C. § 824a(c)(1).
[92] *Emergency*, Webster's New International Dictionary of the English Language (1930).
[93] *Emergency*, Merriam-Webster Dictionary (Jan. 11, 2026); *See* also Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789, 812 n.147 (2025) (noting that dictionaries have given the term "emergency" the "same meaning for many years").
[94] 16 U.S.C. § 824a(c).
[95] *Id.*

particular fuel source[96] or interventions to address general concerns about long-term resource adequacy.[97]

The legislative history of the FPA confirms that Congress intended Section 202(c) authority to be used for true emergencies. In a report accompanying the FPA's original passage in 1935, Section 202(c) is described as a "temporary power" to be used in response to "crises:"

> This is a temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose. Drought and other natural emergencies have created similar crises in certain sections of the country; such conditions should find a [f]ederal agency ready to do all that can be done in order to prevent a break-down in electric supply.[98]

Section 202's overall structure also highlights Section 202(c)'s emphasis on imminent, near-term concerns. Section 202 established three tiers of federal involvement in grid coordination. Section 202(a)[99] and Section 202(b)[100] together define and limit the tools by which the federal government may pursue "abundant" energy supplies in the normal course. Section 202(a) states that the federal government may seek "abundant supply of electric energy" by "divid[ing] the country into regional districts for the voluntary interconnection and coordination of facilities

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[96] *Richmond Power & Light*, 574 F.2d at 615 (Section 202(c) "is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.").
[97] *See Coalition for Competitive Electricity, Dynergy Inc. v. Zibelman*, 906 F.3d 41, 50 (2018) (citing 16 U.S.C. § 824(b)) (FPA "leaves to the States alone" the authority "to regulate energy production and facilities used for the generation of electric energy"); *see also Arkansas Elec. Co-op Corp. v. Arkansas Public Service Comm'n*, 461 U.S. 375, 377 (1983) ("[T]he regulation of utilities is one of the most important of the functions traditionally associated with the police power of the States.").
[98] S. Rep. No. 74-621 at 49 (1935).
[99] 16 U.S.C. § 824a(a).
[100] *id.* § 824a(b).

for the generation, transmission, and sale of electric energy." Section 202(b) provides a backstop if the voluntary interconnection and coordination provided for in Section 202(a) fails, allowing the federal government to order "physical connection . . . to sell energy or to exchange energy" upon application, and "after an opportunity for hearing."[101] However, Section 202(b) specifically states that the government has "no authority to compel the enlargement of generating facilities for such purposes."[102]

The resulting statutory "machinery for the promotion of the coordination of electric facilities" comprises the following: in subsection (a), an instruction to establish a general framework meant to facilitate "coordination by voluntary action;" in subsection (b), "limited authority to compel interstate utilities to connect their lines and sell or exchange energy," subject to defined procedural and substantive requirements, when "interconnection cannot be secured by voluntary action;" and in subsection (c), "much broader" but "temporary" authority "to compel the connection of facilities and the generation, delivery, or interchange of energy during times of war or other emergency."[103]

This structure relies on voluntary action for everyday energy planning, specifies limited authority where that voluntary system fails, and allows for "temporary" central command-and-control only in case of "emergency." Section 202(c) authority applies narrowly to immediate and unavoidable "break-down[s] in electric supply," rather than mere desire for more abundant supply in the future.[104] Interpreting

[101] *Id.*
[102] *Id.*
[103] S. Rep. No. 74-621 at 49 (1935).
[104] *Id.*

Section 202(c)'s "emergency" powers to encompass longer-term concerns such as potential shortfall years into the future would unwind the careful balance of voluntary, market-driven action and federal authority set out by Congress. Therefore, such an interpretation cannot be squared with the statutory text, history and structure of Section 202 as required by law.

ii. Section 215 of the FPA explicitly assigns federal regulation of long-term resource adequacy to FERC, further emphasizing that the Department's Section 202(c) authority is limited to imminent emergencies.

Section 215 of the FPA, 16 U.S.C. § 824o ("Section 215"), which delineates the scope of federal power to enforce mandatory long-term reliability requirements, confirms that Section 202(c) cannot be used to enforce the Department's preference for long-term reliability solutions. Congress added Section 215 to the FPA in 2005 precisely because the FPA as it then existed, which included Section 202(c), did not provide the federal government with the power to enforce measures designed to ensure broad, long-term reliability.[105] Implementation of Section 215, including the approval and enforcement of reliability standards for all entities operating in the bulk power system, is left to FERC and its designated ERO, not the Department.[106]

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[105] *See* Rules Concerning Certification of the ERO; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards, 70 Fed. Reg. 53117, 53118 (Sept. 7, 2005) ("In 2001, President Bush proposed making Electric Reliability Standards mandatory and enforceable[,]" leading to enactment of Section 215 in 2005); National Energy Policy Development Group, *Reliable, Affordable, and Environmentally Sound Energy for America's Future* (May 2001) at 7-6 (noting that "[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country" and that "[o]ne factor limiting reliability is the lack of enforceable reliability standards" because "the reliability of the U.S. transmission grid has depended entirely on voluntary compliance," and then recommending "legislation providing for enforcement" of reliability standards) (emphasis added); S. Rep. No. 109-78,109th Cong., 1st Sess. at 48, Section 1211 (2005) (Section 215 "changes our current voluntary rules system to a mandatory rules system" for long-term reliability); *see Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005, "the reliability of the nation's bulk-power system depended on participants' voluntary compliance with industry standards").

[106] 16 U.S.C. § 824o.

By enacting Section 215, Congress newly created a comprehensive and carefully circumscribed scheme to allow FERC—not the Department—to address long-term reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent "of the users and owners and operators of the bulk-power system" but with "fair stakeholder representation."[107] FERC may approve or remand those standards (but not replace them with its own) and must "give due weight" to NERC's "technical expertise" while independently assessing effects on "competition."[108] Section 215 specifies enforcement mechanisms and procedures for reliability standards and carefully preserves state authority over "the construction of additional generation" and regulation of in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards.[109]

Interpreting Section 202(c) to permit the Department to mandate generation based on its determination that non-imminent and unsubstantiated reliability concerns create an "emergency" would effectively allow the Department to bypass Section 215's procedural safeguards, constraints on federal authority, and protection of state power over long-term reliability. This would impermissibly contradict Congress' clear intent as expressed in its more recent reliability-specific provisions, enacted with the understanding that the Department had no authority to address

[107] 16 U.S.C. § 824o(c)(2)(A); s*ee also id.* § 824o(a)(3) (defining reliability standards as "a requirement . . . to provide for reliable operation of the bulk-power system").
[108] *Id.* § 824o(d)(2)-(4).
[109] *Id.* §§ 824o(e), -(i)-(j).

long-term reliability through Section 202(c).[110] "Congress's specific and limited enumeration of [agency] power" over a particular matter in one section of the FPA "is strong evidence that [a separate section] confers no such authority on [an agency]."[111] Congress has, in Section 215, directly established the mechanisms by which the federal government may compel action to ensure long-term electric-system reliability, and that authority does not rest with the Department. In so doing, Congress has confirmed that the word "emergency," as used in Section 202(c), does not extend to long-term reliability concerns and only applies to specific, imminent, unexpected and temporary events.

iii. The Renewed Order is arbitrary, capricious and contrary to law because it contradicts the Department's regulations interpreting Section 202(c) and its historic practice in applying Section 202(c).

The Department's regulations confirm that Section 202(c)'s authority is confined to imminent and unexpected resource shortages rather than long-term reliability concerns. Those regulations define "emergency" for the purposes of Section 202(c) to mean circumstances that arise suddenly and unexpectedly:

> "Emergency," as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected "entity" to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which

[110] *See also FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 121 (2000) ("The meaning of one statute may be affected by other Acts, particularly where Congress has spoken subsequently and more specifically to the topic at hand.").
[111] *Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401 (D.C. Cir. 2004).

> prohibits the use of certain electric power supply facilities.[112]

This focus on specific events like weather conditions, acts of God, or unforeseen circumstances outside of the power of the affected entity to prevent, along with the reference to a "sudden increase in customer demand" producing a "specific inadequate power supply situation,"[113] forecloses the Department from using 202(c) authority to address vague long-term supply and reliability issues, such as those articulated in the Renewed Order.

This need for specificity is repeated in the Department's regulations defining an inadequate energy supply: "[a] system may be considered to have inadequate" supply when "the projected energy deficiency . . . will cause the applicant [for a 202(c) Order] to be unable to meet its normal peak load requirements based upon use of all of its otherwise available resources so that it is unable to supply adequate electric service to its ultimate customers."[114] An emergency may exist where past planning failures produce an immediate, present-tense shortfall, but the Department has no authority to commandeer long-term planning merely because it deems current plans inadequate to meet long-term needs.[115] As the Department stated when it promulgated these regulations, the statute allows the Department to provide "assistance [to a utility] during a period of unexpected inadequate supply of electricity," but does not empower it to "solve long-term problems."[116]

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[112] 10 C.F.R. § 205.371.
[113] *Id.*
[114] 10 C.F.R. § 205.375.
[115] *See id.* (requiring present inability to meet demand to demonstrate inadequate energy supply).
[116] Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39984, 39985–86 (Aug. 6, 1981).

Until 2025, the Department's orders complied with this regulatory scheme, and the agency used its Section 202(c) authority only in response to concrete, particularized emergencies, subject to narrow, appropriate limitations. Established "practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred."[117] Until recently, the Department has used Section 202(c) to address specific, imminent, and unexpected shortages, never to address longer-term reliability concerns or demand forecasts.[118] As pointed out by the Congressional Research Service, the orders issued by the Department in May 2025 (and subsequently renewed) to keep coal plants open "all involve[d] seemingly new interpretations of the emergency authority."[119] The Renewed Order at issue in this proceeding continues this improper use of Section 202(c).

[117] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941).
[118] *See, e.g.*, Department, Order No. 202-22-4 (Dec. 24, 2022), at 1 (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between December 23 and December 26); Department, Order No. 202-20-2 (Sept. 6, 2020) (responding to shortages produced by ongoing extreme heat and wildfires); *see also* Rolsma, 57 Conn. L. Rev. at 803-4 (describing "sparing[]" use of Section 202(c) outside of wartime shortages during the twentieth century).
[119] Cong. Research Serv., *Federal Power Act: The Department of Energy's Emergency Authority*, CRS Report No. R48568, at 3 (June 12, 2025).

Similarly, before 2025, the Department used Section 202(c) on only three occasions to delay the retirement of generation facilities.[120] Each case met the following four criteria: (1) the order was requested by a system operator or governmental body; (2) the generation facility had ceased or would soon cease operation due to an inability to comply with environmental laws; (3) the request aimed to address a concrete and particularized emergency threatening an imminent loss of load; and (4) the Department tailored its order to go no further than necessary to address the emergency.

The Department's unexplained deviation from its prior interpretation of the statute, as demonstrated through its past practice, is unlawful, arbitrary and capricious.[121] And the Department cannot deviate from its regulations without conducting new notice and comment rulemaking and providing a reasonable basis for any change.[122] A cornerstone of administrative law is "that an agency must provide[ ] a reasoned explanation for departing from precedent or treating similar situations

[120] In 2005, the Department issued an order directing the continued operation of a facility in Alexandria, VA, after the facility was abruptly closed based on noncompliance with its air permit. The order only applied when one or both of the 230 kV transmission lines serving downtown D.C. were out of service. Department, Order No. 202-05-3 (Dec. 20, 2005). In 2017, an Oklahoma state agency asked the Department to direct the continued operation of a unit that would otherwise close because the unit was needed to provide dynamic reactive power support to the local grid, as confirmed by its reliability coordinator. The unit was needed because another unit at the station had been struck by lightning, and the third unit's construction had been delayed due to flooding delaying essential project materials. The Department subsequently ordered the unit to remain in operation for 90 days or until one of the other two units came online, to provide dynamic reactive power support when called upon by its reliability coordinator. Department, Order No. 202-17-1 (Apr. 14, 2017). Finally, in 2017, two Virginia utilities asked the Department to direct the continued operation of two units of a power station because they were necessary to prevent uncontrolled power disruptions and shedding of critical load. Letter from PJM Interconnection, LLC, to the Department (Aug. 24, 2017).

[121] *F.C.C. v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009) ("To be sure, the requirement that an agency provide reasoned explanation for its action would ordinarily demand that it display awareness that it *is* changing position.").

[122] *See* 5 U.S.C. § 553; *F.C.C.*, 566 U.S. at 515 (holding that an agency cannot simply change position on an issue without "a reasoned explanation" and "awareness that it is changing position.").

differently."[123] For this reason, "an interpretation of a legislative rule cannot be modified without the notice and comment procedure that would be required to change the underlying regulation—otherwise, an agency could easily evade notice and comment requirements by amending a rule under the guise of reinterpreting it."[124] The Department has not undertaken any such notice and comment procedure here and has not provided any reasoned justification for its recent departure from the binding requirements and interpretations of its governing statute and regulations.

iv. Courts have found that the Department's use of Section 202(c) is limited to true emergencies and the Department is bound by the courts' statutory interpretation.

There is little case law on Section 202(c). However, two decisions that have addressed the Department's authority under Section 202(c) both recognize that the Department's power under Section 202(c) is limited to specific, imminent, unexpected and temporary events.

First, during the 1973 oil embargo, the Federal Power Commission called for a voluntary transfer of electricity from non-oil power plants to areas of the country that relied heavily on oil, but the New England Power Pool petitioned for a Section 202(c) order because it was not convinced the voluntary program would work.[125] The Commission declined to issue a Section 202(c) order, and instead facilitated an

[123] *New England Power Generators Ass., Inc. v. FERC*, 881 F.3d 202, 210–12 (D.C. Cir. 2018) (quoting *W. Deptford Energy, LLC v. FERC*, 766 F.3d 10, 20 (D.C. Cir. 2014)).
[124] *Env't Integrity Project v. EPA*, 425 F.3d 992, 995 (D.C. Cir. 2005) (internal citations omitted); *see also Center for Biological Diversity v. Haaland*, 998 F.3d 1061, 1067 (9th Cir. 2021) (internal citations omitted) ("When an agency changes its position, it must: (1) "display [ ] awareness that it is changing position," (2) "show "the new policy is permissible under the statute," (3) "believe[ ]" the new policy is better, and (4) provide "good reasons" for the new policy.").
[125] *Richmond Power & Light*, 574 F.2d at 613.

agreement between state commissions and supplying utilities.[126] In *Richmond Power and Light of City of Richmond, Indiana v. FERC*, the D.C. Circuit upheld the Commission's decision to not invoke Section 202(c).[127] The utility argued that the country's dependence on foreign oil, and the high cost and uncertain supply of foreign oil, left the country with a continuing emergency, but the court agreed with the Commission's argument that the facilitated agreement had worked, service was never interrupted, and there was no need for a Section 202(c) order.[128] The court highlighted that the statute "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply[.]"[129] The court upheld the Commission's view that Section 202(c) cannot be used when "supply is adequate but a means of fueling its production is in disfavor."[130]

The Eighth Circuit Court of Appeals has also held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power Co. v. Fed. Power Comm'n.*, a utility insisted a Section 202(c) order was necessary to properly order the utility to connect to a municipal power provider. The demand for electricity in the city had increased, and the peak load of the municipal power provider was high enough that both of its two generators would likely be needed simultaneously in the near future, which could cause a possible loss of service if one of them malfunctioned

[126] *Id.*
[127] *Id.,* at 614.
[128] *Id.,* at 615.
[129] *Id.*
[130] *Id.*

during a peak period.[131] Instead of issuing a Section 202(c) order, the Commission issued an order under Section 202(b), which the utility argued was incorrect.[132]

In upholding the Commission's decision, the court distinguished between an emergency that is likely to occur and one that is actually occurring, concluding that Section 202(b) applies to the former, while Section 202(c) applies to the latter:

> On its face, § 202(c) enables the Commission to react to a war or national disaster and order immediate interconnection of the facilities to maintain electrical service during such emergency. . . On the other hand, § 202(b) applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission.[133]

Therefore, the court agreed that a potential crisis in the foreseeable future was not an emergency, making this current situation "just the type of situation to fit into a Section 202(b) hearing rather than a Section 202(c)."[134]

Because courts, not agencies, decide "all relevant questions of law" arising on review of agency actions, the Department is bound by these courts' "best reading" of the statutory language.[135]

B. Section 202(c) does not vest the Department with general regulatory authority over resource adequacy, which is regulated by the states and FERC under other provisions of the FPA.

The FPA preserves states' authority over generation facilities and resource adequacy planning, and Section 202(c) does not vest the Department with general regulatory authority over resource adequacy. Under the FPA, states are responsible

[131] *Otter Tail Power*, 429 F.2d at 233-234.
[132] *Id.*
[133] *Id.*, at 234.
[134] *Id.*
[135] *Loper Bright Enterprises v. Raimondo*, 603 U.S. 369, 392, 399-400 (2024).

for their own resource adequacy and decisions about generation facilities, and FERC is responsible for assuring the reliability of the nation's bulk power system, including through its oversight of RTOs and ISOs. The Department itself has recognized that "resource adequacy planning and capacity requirements[] have traditionally been the domain of state regulatory commissions, NERC-certified Regional Entities, and RTOs/ISOs."[136] Because there is no imminent shortfall or other circumstance constituting an emergency, the Renewed Order is an illegal attempt to regulate long-term resource adequacy by misusing the Department's Section 202(c) authority.

i. The Renewed Order attempts to use the Department's short-term emergency authority to regulate long-term resource adequacy.

The Department is attempting to regulate long-term resource adequacy and energy production under the guise of a Section 202(c) emergency and is therefore intruding on FERC and state authority.

It is clear from the Renewed Order that the Department is using its Section 202(c) authority for circumstances beyond actual emergencies. The Renewed Order repeatedly references long-term reliability. The Department's determination that an emergency exists rests on the assertion of a long-term concern that "increasing demand and shortage from premature retirement of generation facilities . . . could lead to the loss of power to homes, and businesses" that is "likely to continue in subsequent years."[137] The Renewed and Second Orders both stated that their issuance was necessary "in the long term."[138] The Renewed Order admits that the WECC-Rocky

[136] Research Power Corp., Order No. EA-365-C, Order Authorizing Electricity Exports to Canada (Dep't of Energy Oct. 21, 2025), at 5.
[137] Exhibit KKK, at 6.
[138] Exhibit TT; Exhibit KKK.

Mountain region, where it has currently declared there to be an energy emergency, is expected to have "Anticipated Reserve Margins [that will] remain above the Reference Margin Level"[139] for the three month time period covered by the Renewed Order. As evidence of an energy emergency, the Renewed Order cites only the 2025 WECC Assessment's assertion that the "West *could* see energy shortfalls as early as *2028*." [140] First putting aside the fact that "the West" in this case refers to seven other subregions besides the Rocky Mountain subregion, attempting to remedy vague assertions of a potential energy shortfalls two years from now at the earliest falls into the realm of long-term resource planning, not a Section 202(c) emergency, which must be imminent, unexpected, sudden, and temporary.[141] And when looking at the 2025 WECC Assessment's outlook for the relevant Rocky Mountain subregion, shortfalls are not expected until 2030, and only in a scenario where only 67% of planned resources are acquired.[142] Given that the Renewed Order purports to address an emergency in the Rocky Mountain subregion, the Department cannot credibly say that an "emergency" that comes in the form of potential energy shortfalls four years from now are reddressable by a 90-day 202(c) order, particularly where those potential shortfalls are anticipated only if 67% of resource acquisitions go through. That is a long-term resource planning concern.

[139] Exhibit KKK, at 4.
[140] *Id.*, at 4 (emphasis added).
[141] *See supra*, Section V.A.
[142] Exhibit VVV.

ii. Regulating long-term resource adequacy is outside the scope of the Department's Section 202(c) authority.

The structure and language of the FPA reflect Congress' deliberate choice to preserve the states' traditional authority over generating facilities and to limit the Department's emergency authority. The FPA states that "the Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy . . ."[143] Congress also recognized the states' exclusive authority over generating facilities in Section 202(b), which provides that FERC's interconnection authority does not include the power to "compel the enlargement of generating facilities for such purposes."[144] FERC's role in regulating electricity generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the [s]tates."[145]

Pursuant to the FPA, "[t]he states are thus authorized to regulate energy production . . . and facilities used for the generation of electric energy."[146] Decisions around what facilities to build, whether they remain feasible, and retail rates are areas governed by the states.[147] The Supreme Court has acknowledged that "States retain their traditional responsibility in the field of regulating electric utilities for determining questions of need, reliability, cost, and other related safety concerns.

[143] 16 U.S.C. § 824(b)(1).
[144] 16 U.S.C. § 824a(b).
[145] 16 U.S.C. § 824(a).
[146] *Coal. for Competitive Elec.*, 906 F.3d at 50.
[147] *Pac. Gas & Elec. Co. v. State Energy Res. Conservation and Dev. Comm'n*, 461 U.S. 190, 205 (1983).

Need for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States."[148] Courts have also held that Section 201(b)(1) reserves to the states authority over electric generating facilities, including that states retain the right "to require the retirement of existing generators" or to take any other action in their "role as regulators of generation facilities."[149] FERC has acknowledged that "[r]esource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsive for procuring adequate capacity to serve loads within their respective jurisdictions."[150] As relevant to Craig Unit 1, because SPP does not have a capacity market, states are still required to ensure utilities have sufficient generation capacity to meet their needs; SPP simply determines when to dispatch it. While many RTOs or ISOs have a centralized capacity market, SPP instead uses a resource adequacy requirement that establishes minimum capacity levels but maintains traditional state authority over how to meet those minimum levels.

The electric power sector is governed by longstanding principles of cooperative federalism encouraged in Section 209(b) of the FPA, which explicitly declares that FERC may consult with states "regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction of such State commission and of the Commission."[151] FERC

[148] *Id.*
[149] *Conn. Dep't of Pub. Util.*, 569 F.3d at 481; *see also Hughes*, 578 U.S. at 155.
[150] *Devon Power LLC, et al.*, 109 FERC ¶ 61,154, at 47 (2004).
[151] 16 U.S.C. § 824h(b).

has embraced these cooperative federalism principles and developed long-standing consultation practices with the states, including through creation of a Joint Federal-State Task Force,[152] and more recently, a Federal-State Current Issues Collaborative which was formed due to the success of the Task Force.[153] The importance of this cooperation is evident in the Department's own Resource Adequacy Report, which flagged that it could have benefitted greatly from cooperation with the states due to the "in-depth engineering assessments which occur at the regional and utility level."[154]

In the Renewed Order, the Department seeks to substitute its own judgment about which resources should be employed to maintain resource adequacy for the states' decisions, despite these decisions resting firmly in the jurisdiction of the states. Section 202(c) does not provide the Department with the authority to mandate that resources remain running to address long-term resource adequacy. If Congress intended to vest regulatory authority over long-term resource adequacy in Section 202(c) and displace state law, it would have needed to make that intent "unmistakably clear."[155] Section 202(c) says that the Department may "require by order . . . such generation . . . of electric energy as in its judgment will best meet the emergency and serve the public interest."[156] Empowering the Department to generally

[152] FERC, *Joint Federal-State Task Force on Electric Transmission* (Sept. 3, 2025).
[153] FERC, *Federal-State Current Issues Collaborative* (Jan. 21, 2026).
[154] Department, *Resource Adequacy Report Evaluating the Reliability and Security of the United States Electric Grid* (July 2025) at 2.
[155] *Gregory v. Ashcroft*, 501 U.S. 452, 460 (1991) (The clear statement rule requires Congress to make its intent unmistakably clear if it intends a statute to alter the usual constitutional balance between the federal government and the states.); *see also DeMarco v. Holy Cross High Sch.*, 4 F.3d 166, 169 (2d Cir. 1993) (Congress must express an affirmative intention to use a statute to alter the federal balance.).
[156] 16 U.S.C. § 824a(c)(1).

determine which power plants may retire across every utility and independent power producer in the entire country would have profound implications for rates, state sovereignty, and a broad array of other state policy and stakeholder interests. If Congress had intended to do that, it would not have done so through the only provision in the FPA that empowers the Department to act outside normal procedural safeguards.

The Supreme Court has rejected statutory interpretations where an agency "claim[s] to discover in a long-extant statute an unheralded power representing a transformative expansion in its regulatory authority."[157] The Department may not radically reinterpret a 90-year-old statute to manufacture a basis to exercise much broader authority than it ever has in the past. Previous exercises of Section 202(c) authority have been at the request of a system operator or governmental body and in a manner narrowly tailored to respond to a concrete and particularized emergency. Prior to the current administration, the Department has never issued a Section 202(c) order to impose its policy preferences to contravene the judgment of those bodies properly responsible for ensuring resource adequacy, *i.e.*, the states and FERC. For these reasons, the Renewed Order should be withdrawn.

[157] *W. Virginia v. EPA*, 597 U.S. 697, 724, (2022) (quoting *Util. Air. Regul. Grp. V. E.P.A.*, 573 U.S. 302, 324 (2014)) (internal quotations omitted).

C. The Renewed Order fails to present substantial evidence for its emergency determination and ignores critical facts.

Agencies "must examine the relevant data and articulate a satisfactory explanation for [their] actions, including a rational connection between the facts found and the choice made[,]" and make findings that are supported by substantial evidence.[158] Substantial evidence is "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion."[159] Similarly, orders under the FPA must reflect "a principled and reasoned decision supported by the evidentiary record."[160] Here, the Department failed to provide evidence of an imminent resource adequacy shortfall, making the Renewed Order contrary to law.

The Renewed Order cites the following purported evidence of an emergency: a conclusory statement that the production of electricity from Craig Unit 1 continues to be critical to maintain reliability; WECC's 2025 Western Assessment of Resource Adequacy, the 2026 SRA, and the Department's Resource Adequacy Report; generation retirements and summer resource adequacy forecasts in Colorado; and the Grid Reliability and Energy Emergency Executive Orders, data center load growth, and a recent Presidential Memorandum.[161] Contrary to the Renewed Order's claims, these reports and observations, whether considered separately or together, do not provide sufficient evidence of an energy emergency in the WECC-Rocky Mountain assessment area.

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[158] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (quoting *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962)).
[159] *Chritton*, 888 F.2d at 856 (quoting *Refrigerated Transport Co., Inc. v. I.C.C.*, 616 F.2d 748, 751 (5th Cir.1980) (quoting *Chem-Haulers, Inc. v. United States*, 536 F.2d 610, 617 (5th Cir.1976)).
[160] *Emera Maine*, 854 F.3d at 22.
[161] Exhibit KKK.

i. Minimal usage of Craig Unit 1 over the past seven months does not demonstrate an emergency.

The Renewed Order states that the "production of electricity from Craig Unit 1 *continues to be critical* to maintain reliability in the WECC-Rocky Mountain assessment area."[162] At best, this is a misrepresentation of the need for and use of Craig Unit 1. From the issuance of the Original Order on December 31, 2026, to the date of this request for rehearing, a period of almost seven months, Craig was only called up to run a handful of times, including once for about two weeks in April, which was immediately upon Tri-State and PRPA's entrance to SPP RTO, and for about a week in July.[163] This means that Craig Unit 1 has run for a total of around two weeks in a seven-month period, and mostly at minimum capacity.[164] Craig Unit 1 also likely had to run longer than was needed for the circumstances it was called up to address, because the unit has a minimum run time of approximately four to five days, which is longer than the typical resource alerts called by SPP in this period. The Department fails to include in its Renewed Order evidence sufficient to demonstrate that Craig Unit 1 was needed to address an emergency, and the bare fact of Craig Unit 1's minimal usage does not constitute evidence of an emergency requiring the continued availability of Craig Unit 1.

And when Craig Unit 1 did run, it did so at the direction of SPP, for SPP's needs, not to maintain reliability in the WECC-Rocky Mountain assessment area. Tri-State and PRPA continue to assert that they do not need Craig Unit 1 to maintain their

[162] *Id.*, at 3 (emphasis added).
[163] Exhibit B, ¶¶ 17-20.
[164] *Id.*, ¶ 19.

system reliability, and the remaining co-owner located in the Rocky Mountain assessment area, Public Service, is not in SPP and therefore did not benefit from Craig's operation on the rare occasion that it did run.[165]

ii. NERC's assessments do not establish that there is an energy emergency in the areas served by Craig Unit 1.

The Renewed Order cites the 2026 SRA's statements that the WECC-Rocky Mountain assessment area's anticipated reserve margins will remain above the reference margin level for the summer of 2026, and that wildfires and extreme heat conditions pose the greatest reliability risk scenario for the Rocky Mountains.[166] The Renewed Order relies on these statements to assert the WECC-Rocky Mountain assessment area is experiencing an energy emergency. This mischaracterizes and misapplies the 2026 SRA's conclusions. By failing to consider relevant facts and to support its findings with substantial evidence, the Department's Renewed Order is contrary to law.

The 2026 SRA assessment does not actually demonstrate an emergency for the WECC-Rocky Mountain assessment area, contrary to the Renewed Order's claims. In terms of resource adequacy in the WECC-Rocky Mountain region, the Renewed Order itself states that the Rocky Mountain assessment area's "Anticipated Reserve Margins will remain above the Reference Margin Level," but goes on to cite to the 2026 SRA's statement that "'wildfires in the region, along with extreme heat conditions for the summer, pose the greatest reliability risk scenario for the Rocky Mountains . . .

[165] Exhibit UU; Exhibit MMM.
[166] Exhibit KKK.

[which] can impact rural communities disproportionately.'"[167] NERC's general recognition of a possible reliability risk from wildfires does not negate its overall assessment that the WECC-Rocky Mountain Region's resource adequacy criteria are met and the region is expected to have sufficient resources for extreme conditions during the time period addressed by the Renewed Order.[168]

The Renewed Order also ignores that the WECC-Rocky Mountain assessment area has existing certain and anticipated reserve margins of 43% and 52% respectively, which are over approximately triple the reference margin level of 15%.[169] Even in a scenario with higher demand, outages, and derates (an intentional reduction of the operating capacity of an electric generating unit) in extreme conditions, the Rocky Mountain assessment area has an anticipated reserve margin of 21.5%.[170] Furthermore, internal demand has slightly decreased from 2025, and tier 1 planned capacity has increased by 1059.6%.[171] Importantly, the units forced to stay online by 202(c) orders were not incorporated into the analysis of anticipated resources for assessment areas.[172]

The 2026 SRA therefore does not provide substantial evidence of an energy emergency in the WECC-Rocky Mountain assessment area.

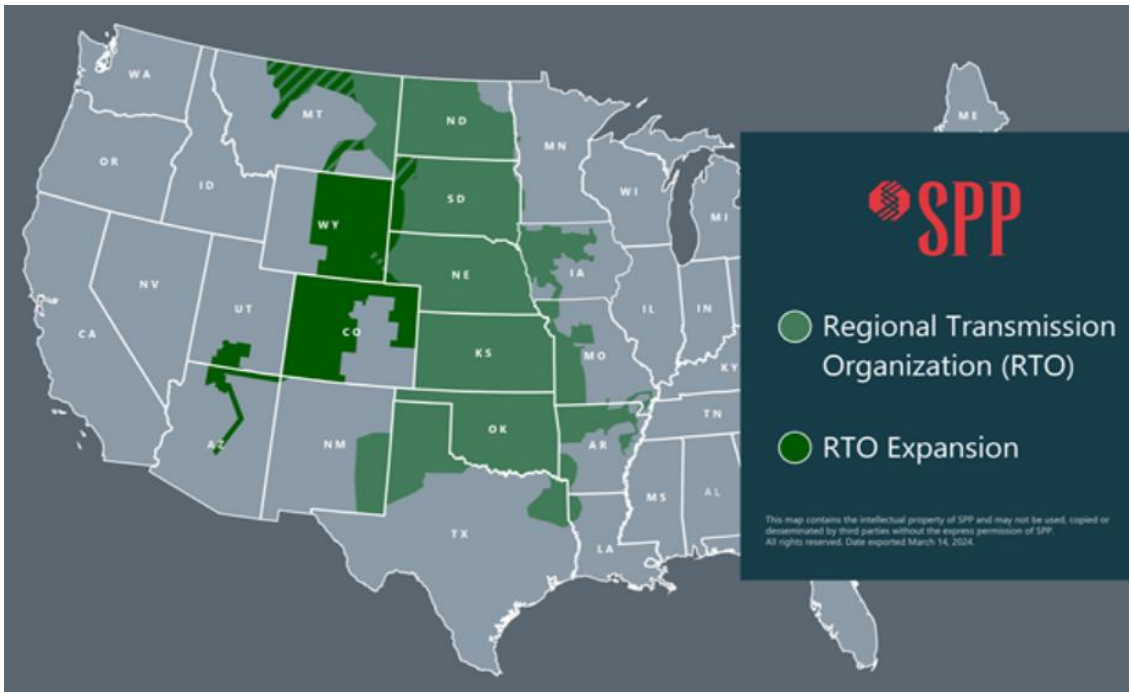
[167] *Id.*, at 4-5.
[168] Exhibit NNN.
[169] *Id.*, at 37.
[170] *Id.*, at 10.
[171] *Id.*, at 50; Exhibit VVV
[172] Exhibit NNN.

Even if the 2026 SRA contained some indication of reliability concerns, the Department's reliance on the 2026 SRA as evidence of an emergency is fundamentally flawed. NERC serves an important advisory role by providing recommendations about risks to the grid, but ultimately, determinations about generation resources remain within state authority.[173] Importantly, NERC's reports do not examine regions at the level of granularity that would be required to determine whether a particular resource is essential for regional resource adequacy. The reports only provide the anticipated planning reserve margins of large regions as a whole. The purpose of NERC assessments is to identify for grid operators constraints that might arise and implicate grid reliability if not mitigated.[174] Thus, even "at risk" designations are not grid emergencies. They merely reflect potential areas of future concern so that the relevant grid operators and planners for the applicable region can consider whether mitigation measures are necessary to maintain grid reliability, under their set procedures.

The Department's choice to rely on the 2026 SRA is also flawed because the 2026 SRA does not account for the fact that Tri-State and PRPA have joined the SPP RTO. SPP's new footprint after its April 1, 2026, western expansion is demonstrated in the figure below:

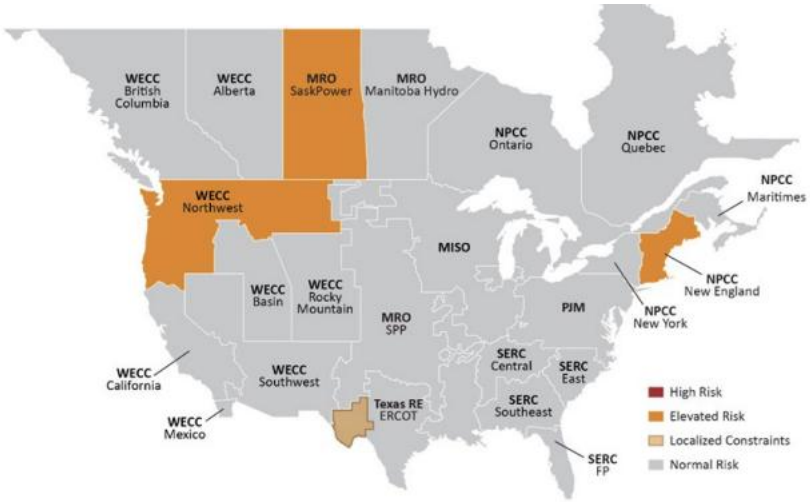
[173] NERC, *Reliability Assessments* (2026).
[174] Exhibit L.

Figure 1: SPP Expanded RTO Footprint[175]



The other 2026 SRA assessment areas match up with RTO and ISO footprints, as shown in the map below:

Figure 2: NERC Assessment Areas Map[176]



[175] SPP, *RTO Expansion*, Western Services (Apr. 1, 2026) (map at top of page).
[176] Exhibit NNN, at 3.

The MRO-SPP and WECC-Rocky Mountain assessment area no longer accurately reflect operational and planning realities, as well as RTO footprints.

Thus, it is unreasoned for the Department to rely on the 2026 SRA as substantial evidence of a reliability concern in the WECC-Rocky Mountain assessment area.

iii. WECC's Western Assessment of Resource Adequacy and the Department's Resource Adequacy Report do not demonstrate an emergency.

The Renewed Order also cites the 2025 WECC Western Assessment of Resource Adequacy ("2025 WECC Assessment") to support its declaration of an emergency. The 2025 WECC Assessment does not analyze near-term resource adequacy and instead uses a probabilistic approach to evaluate reliability over the next ten years.[177] This makes the 2025 WECC Assessment inappropriate for providing evidence of an emergency under Section 202(c).

Even if the 2025 WECC Assessment was appropriate evidence for the Department to rely upon, it does not demonstrate an emergency in the areas served by Craig Unit 1 or the WECC-Rocky Mountain subregion.[178] Once again, the Department selectively cites information from that report.[179] The Renewed Order mentions long-term resource adequacy concerns regarding the Basin and Northwest subregions, despite the fact that the Renewed Order only designates an emergency for the WECC-Rocky Mountain subregion.[180] The Renewed Order cites WECC's vague

[177] WECC, *2025 Western Assessment*, WECC Feature (last visited Apr. 27, 2026).
[178] The Rocky Mountain subregion used in the WECC assessments is equivalent to the Rocky Mountain assessment area used in the NERC assessments.
[179] Exhibit KKK.
[180] Exhibit UUU, (WECC, Summer 2026 Assessment Overview).

statement that "[t]he West could see energy shortfalls as early as 2028"[181] without explaining why potential shortfalls located somewhere in the West, which WECC's supporting documents assign to the Northwest subregion,[182] result in an emergency in the Rocky Mountain subregion.

The Renewed Order also states that planned resources are largely inverter-based resources, but it fails to demonstrate how that results in an imminent reliability risk for the Rocky Mountain subregion. In fact, the WECC Summer Reliability Assessment Western Overview 2026 ("WECC 2026 Summer Assessment") finds the potential variability of inverter-based resources to be a concern for the California subregion, not the Rocky Mountain subregion.[183]

Finally, the Renewed Order states "that entities plan to retire 22 GW [of largely baseload] generation over the next 10 years."[184] Again, the Renewed Order does not identify how much of that generation is in the Rocky Mountain subregion and provides no evidence that those retirements would pose a concern even if they were in the Rocky Mountain subregion. The Renewed Order then fails to acknowledge the 2025 WECC Assessment's actual findings for the Rocky Mountain subregion, namely that the Rocky Mountain subregion is again designated as normal risk. According to WECC, the subregion does not have demand at risk hours until 2030, where it has one loss of load hour, only in a scenario where 67% of resource additions are completed on

[181] Exhibit KKK, at 4.
[182] Exhibit VVV (WECC, 2025 Western Assessment Supplemental Information).
[183] Exhibit UUU.
[184] Exhibit KKK, at 4.

time.[185] Thus, the 2025 WECC Assessment does not provide substantial evidence of an emergency in the WECC-Rocky Mountain subregion.

The Department also completely fails to acknowledge the more recent and more relevant WECC 2026 Summer Assessment.[186] The WECC 2026 Summer Assessment "covers the upcoming summer season," the same period covered by the Renewed Order, "providing an evaluation of reliability for projected risk periods,"[187] whereas the 2025 WECC Assessment "provides a high level examination of resource-adequacy-related risks to the reliability of the Western Interconnection over the next 10 years . . . This work is intended to help stakeholders target specific areas and topics for deeper evaluation and mitigation."[188]

The WECC Summer 2026 Assessment found for the Rocky Mountain subregion that "peak demand is projected to decline by 3%, while anticipated resource capacity is expected to increase by 15%."[189] The WECC Summer 2026 Assessment also points out that although "[c]limate change and ecological factors are raising the wildfire risk in the subregion, [] the entities have engaged in substantial mitigation efforts."[190] The Rocky Mountain subregion is not one of the three areas that face an elevated risk of supply shortfalls during periods of more extreme summer conditions.[191]

[185] Exhibit VVV.
[186] Exhibit UUU.
[187] *Id.*, at 2.
[188] Exhibit VVV, at 2.
[189] Exhibit UUU, at 6.
[190] *Id.*
[191] *See generally id.*

Next, the Renewed Order briefly references the Department's Resource Adequacy Report,[192] which purports to provide a uniform methodology for identifying at-risk regions and grid reliability issues and guide reliability interventions. As with other reports cited in the Renewed Order, this Report provides no support for the Department's determination that there is an emergency requiring continued availability of Craig Unit 1 in the next 90 days, or even the next year. The Report assesses the ability of the electric grid to "meet *future* demand through 2030" and is a "*forward-looking* snapshot of resource adequacy."[193] This Report was not designed to assess imminent emergency conditions of the electric grid and explicitly does not do so.

Indeed, the Report's only conclusions are for 2030, which is completely irrelevant for an emergency Section 202(c) order issued for 90 days in 2026. The Report finds potential reliability issues in 2030 only under a set of unsupported assumptions that assume unrealistically high load projections stemming from unfounded assumptions about data center load and assume that utilities virtually cease construction of new generation and transmission resources. Its 2030 projections are at odds with the analyses from NERC and WECC, as well as the findings from Colorado's ERP proceedings and utilities' resource adequacy reporting. In any case, a claimed reliability issue in 2030 cannot justify a 90-day emergency order in 2026. Forcing ratepayers to pay to keep generation online that is not needed, simply because technology companies may be building more data centers in the future that

[192] Exhibit M.
[193] Department, *Resource Adequacy Report Evaluating the Reliability and Security of the United States Electric Grid* (July 2025), at 9 (emphasis added).

may need power is arbitrary and violates the FPA's requirement that rates be just and reasonable, especially as other analyses indicate that data center projections may be overblown.[194]

Given their focus on non-imminent future conditions and unverified assumptions, neither the 2025 WECC Assessment nor the Department's Resource Adequacy Report provide substantial evidence of an emergency under Section 202(c).

iv. The Executive Orders and Presidential Memorandum cited in the Renewed Order are not evidence of an energy emergency.

The Renewed Order relies on the Energy Emergency and Grid Reliability Executive Orders as evidence of an energy emergency, generally stating that the Energy Emergency and Grid Reliability Executive Orders underscore "the [ ] energy challenges facing the Nation due to growing resource adequacy concerns[.]"[195] The Renewed Order also cites to a White House Memorandum issued by President Trump to the Secretary of Energy ("Coal Memorandum") that emphasizes the findings of the Energy Emergency Executive Order.[196] However, these executive orders and the memorandum do not present evidence of an energy emergency in the WECC-Rocky Mountain assessment area or any other region of the country within the meaning of Section 202(c).[197]

[194] Exhibit SS (Behr, P., *PJM to ratchet down projected AI power demand for eastern US* (Jan. 6 , 2026)); Institute for Policy Integrity, *Fiscal Year 2025 Annual Report*; London Economics International LLC, *Uncertainty and Upward Bias are Inherent in Data center Electricity Demand Projections* (July 7, 2025).
[195] Exhibit KKK, at 5.
[196] *Id.*
[197] *See* 10 C.F.R. § 205.371 (2026) (defining emergency as a "specific inadequate power supply situation").

On January 20, 2025, President Trump issued Executive Order 14156, *Declaring a National Energy Emergency* ("Energy Emergency Executive Order").[198] Despite its title, the Energy Emergency Executive Order fails to describe any type of energy emergency. It generically claims "[t]he energy. . . generation capacity of the United States [is] far too inadequate to meet our Nation's needs," and the situation "will dramatically deteriorate in the near future . . . "[199] The Energy Emergency Executive Order also specifically calls out the Northeast and West Coast states, claiming those states' "dangerous" "policies jeopardize our Nation's core national defense and security needs, and devastate the prosperity of not only local residents but the entire United States population."[200] The Executive Order does not identify any specific policies or explain how they are jeopardizing grid reliability.

President Trump then issued Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, ("Grid Reliability Executive Order") on April 8, 2025.[201] The Grid Executive Order also claims that the country is "experiencing an unprecedented surge in electricity demand," generically pointing to expansions of data centers and increases in domestic manufacturing as demand drivers.[202] These vague statements on nationwide energy needs are not sufficiently specific to justify a Section 202(c) order.

[198] Exec. Order 14156, 90 Fed. Reg. 8433, 8434 (Jan. 20, 2025).
[199] *Id.*, at Sec. 1.
[200] *Id.*, at 8434.
[201] Exec. Order 14262, 90 Fed. Reg. 15521.
[202] *Id.*

The April 20, 2026, Coal Memorandum emphasizes the findings of the Energy Emergency Executive Order and states that coal supply chains and baseload power generation are essential to the U.S. national defense, and therefore action to expand coal supply chain capacity and baseload generation availability is necessary.[203]

Neither of these Executive Orders nor the Coal Memorandum provide data or other evidence in support of their claims of inadequate nationwide generation, let alone evidence of inadequate generation in the areas served by Craig Unit 1 such that they could constitute the evidence required to support the Renewed Order. The Energy Emergency Executive Order refers to a deterioration "in the near future,"[204] while the Grid Reliability Executive Order offers no projection for the timing or location of the increased demand it speculates.[205] The Coal Memorandum states that the "Nation's current inadequate and intermittent energy supply leaves us vulnerable . . ." with no evidence to support that statement.[206] The generalized statements in these unsupported executive documents do not satisfy Section 202(c)'s requirements, discussed above in Section V.A., that an emergency must be specific and imminent.

[203] Memorandum on Presidential Determination Pursuant to Section 303 of the Defense Production Act of 1950, as Amended, on Grid Infrastructure, Equipment, and Supply Chain Capacity, Pres. Determination No. 2026-11 (Apr. 20, 2026).
[204] Exec. Order 14156 at 8433.
[205] *Id.*
[206] Memorandum on Presidential Determination Pursuant to Section 303 of the Defense Production Act of 1950, as Amended, on Grid Infrastructure, Equipment, and Supply Chain Capacity, Pres. Determination No. 2026-11 (Apr. 20, 2026).

Importantly, the facts contradict the vague assertions of an energy emergency contained in the Executive Orders and the Coal Memorandum. For example, America's domestic energy production is at an all-time high given its diverse mix of both fossil and non-fossil fuel resources. The United States is producing record quantities of oil and natural gas,[207] and has been a net energy exporter since 2019.[208] The Energy Emergency Executive Order's assertion that the United States has an "inadequate and intermittent energy supply, and an increasingly unreliable grid" is unsupported by the facts.[209] NERC reports that the bulk power system is resilient, and that the largest challenge for reliability is extreme weather induced by climate change.[210] Renewable energy resources both mitigate climate change and improve the overall reliability and affordability of the United States' energy supply by tempering the impact of international commodity price swings on natural gas prices and reducing grid operators' reliance on interruptible natural gas deliveries.[211] Solar and wind generated more than 15% of all electricity and 8% of all energy consumed in the United States in 2024.[212] The 2026 SRA found that a large influx of generation resources has outpaced demand and is boosting reserves, and that battery resource additions help maintain stable frequency on the grid.[213] The WECC Summer 2026 Assessment found that "[a]n influx of resources, primarily solar and battery but also natural gas-fired generation, has outpaced demand and boosted reserves, easing resource adequacy concerns across the continent."[214]

Next, the Renewed Order relies in part on "the expansion of artificial intelligence data centers" referenced in the Grid Reliability Executive Order and other projected demand growth noted in the Department Resource Adequacy Report

to support its finding of an emergency.[215] But the Order's discussion of data center load growth is both irrelevant and unsubstantiated.

Neither the Grid Reliability Executive Order nor the Renewed Order specify any timeframe for when the increased energy demand from data centers is expected to occur. Section 202(c) does not give the Department the authority to retain generation units for possible conditions that may arise at some indeterminate time in the future. Authority to address long-term threats to resource adequacy rests with the states and FERC and its designated entities, all of which are aware of and extensively planning for this potential load growth. The Renewed Order does not cite any evidence that data center load growth will occur in the areas served by Craig Unit 1 during the 90-day period of the Renewed Order. As demonstrated in their respective resource plans, the Craig Unit 1 owners have sufficient capacity for any new data centers or other large loads over 50 MW that are scheduled to come online in their service territory in the next 90 days.[216] And where Colorado utilities anticipate data centers coming online in the next five years, they are planning for that additional load through their established resource planning processes.

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[207] U.S. Energy Information Admin. ("EIA"), *Short-Term Energy Outlook Data Browser* (Jan. 13, 2026).
[208] EIA, *In-Brief Analysis: The United States was the world's largest liquified natural gas exporter in 2023* (Apr. 1, 2024); EIA, *U.S. Exports of Crude Oil* (Dec. 31, 2025); EIA, *U.S. Energy Facts Explained* (July 15, 2024).
[209] Exec. Order 14156 at 8433.
[210] NERC, *2024 State of Reliability* (June 2024), at 5.
[211] FERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 16, 2021), at 172 ("Natural gas fuel supply issues alone caused 27.3[%] of the generating unit outages" during Winter Storm Uri).
[212] EIA, *Short-Term Energy Outlook* (Feb. 11, 2025), *see* the 2024 data; EIA, *December 2025 Monthly Energy Review* (Dec. 23, 2025).
[213] Exhibit NNN.
[214] Exhibit UUU, at 2.
[215] Exhibit KKK, at 5.
[216] *See supra,* Section V.D.

D. State and utility planning processes have ensured that the areas served by Craig Unit 1 will continue to have sufficient capacity without Craig Unit 1.

The Renewed Order notes that Colorado's share of coal generated electricity has fallen from 45% to 25% since 2016, that further coal and natural gas plant retirements are planned by 2029, that intermittent wind accounts for 5,300 MW of Colorado's electric generating capacity, and that CoPUC Commissioners have discussed resource adequacy concerns for Summer 2026 as evidence of an energy emergency in the WECC-Rocky Mountain assessment area.[217] However, the Renewed Order does not provide any evidence that any of these factors have resulted in a resource shortfall in Colorado. Pursuant to the authority reserved to the states by the FPA, Colorado has robust electric resource planning processes that ensure resource adequacy and grid reliability. Tri-State and PRPA, the two co-owners of Tri-State that are both located in Colorado and members of SPP, also have robust electric resource planning processes that accounted for the retirement of Craig Unit 1.

i. Colorado's robust planning process ensures sufficient capacity for the State's utility customers.

For decades, Colorado has implemented robust and successful electric resource planning processes that serve as a model for other states. Colorado's process assesses resource adequacy and reliability across utilities' service territories, requires regulated utilities to use competitive resource solicitations to acquire new resources of multiple fuel types, and ensures that there will be sufficient electricity to meet expected load, even with planned plant closures.[218]

[217] Exhibit KKK, at 4.
[218] *See* Exhibit C, ¶¶ 12-17.

As part of Colorado's overall energy planning framework, each investor-owned retail electric utility and wholesale electric generation and transmission cooperative is required to submit to the CoPUC an application for approval of an ERP.[219] Each Colorado ERP proceeding thoroughly considers resource adequacy and reliability at multiple stages.[220] In developing their forecasted resource needs, utilities' electric energy and demand forecasts must be completed for each year within the ERP planning period and must include, among other components, the electric demand placed on the utility's system for each hour of the day for peak-day, average-day, and representative off-peak days for each calendar month.[221] Utilities must "develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period[,] . . . including base case, high, and low" demand growth scenarios.[222] Since the announcement of Craig Unit 1's retirement in 2016, the CoPUC has received annual resource planning reports from Tri-State and Public Service, and has conducted two adjudicated resource planning proceedings for Tri-State's system and three for Public Service's system, with administrative records totaling in the tens of thousands or hundreds of thousands of pages. All of these proceedings have included the planned Craig Unit 1 retirement as a foundational assumption in forecasting, modeling, and portfolio selection.

[219] § 40-2-125.5, Colo. Rev. Stat.; 4 Colo. Code Regs. §§ 723-3-3603(a), -3605(a).
[220] *Id.*
[221] 4 Colo. Code Regs. § 723-3-3605(b).
[222] *Id.* at -(b)(II).

In an ERP proceeding, the utility must describe and justify the means by which it assesses the desired level of system reliability, and it must propose target planning reserve margins for each forecasted scenario.[223] Utilities' planning reserve margin studies employ probabilistic modeling to determine the amount of capacity necessary to maintain a certain level of reliability, for example a Loss of Load Expectation of 0.1 days/year. The studies must account for a wide variety of risks, "includ[ing] risks associated with: the development of generation; losses of generation capacity . . . , losses of transmission capability; [and] risks due to known or reasonably expected changes in environmental regulatory requirements[.]"[224] Planning reserve margin studies also rely on thorough analyses, for each resource type, of the Effective Load Carrying Capability ("ELCC"), or the amount of dependable capacity that can be counted on by the system for resource adequacy purposes.[225] Utilities must present contingency plans for the acquisition of additional resources in the event demand increases or expected generation resources are not developed.[226] "The additional generation must be able to [ ] meet system needs, including availability or dispatchability at certain hours of the day."[227]

Upon completion of a resource solicitation, the utility presents a number of potential resource portfolios. Included in this presentation are the results of additional reliability checks, which further ensure resource adequacy and reliability by demonstrating that each portfolio satisfies relevant metrics such as meeting the

[223] 4 Colo. Code Regs. § 723-3-3605(e).
[224] *Id*. at -(e)(II).
[225] Exhibit C, ¶¶ 23, 43, 54.
[226] 4 Colo. Code Regs. § 723-3-3605(e)(III).
[227] Exhibit C.

required planning reserve margin, meeting a Loss of Load Hours target and meeting an Annual Expected Unserved Energy target.[228] After opportunities for stakeholder input, the CoPUC issues a decision establishing the final cost-effective resource plan. In making this decision the CoPUC considers various statutory factors, including whether the resource plan meets the energy policy goals of Colorado, such as giving full consideration to cost-effective resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.[229]

Colorado's electric resource planning process also allows for the filing of interim ERPs and certificates of public convenience and necessity to fill generation needs not identified or fully satisfied by ERPs completed on the regular cadence.[230] This "allow[s] electric utilities and the State to quickly respond to changes in load or available resources."[231]

The Renewed Order states that CoPUC Commissioners "have expressed concerns about the ability of certain utilities to meet projected summer 2026 loads[,]" citing a March 26, 2026, RTO Insider article titled *Comanche 3 Repair Delay Raises RA Concerns in Colorado*.[232] The Renewed Order's reliance on the article is overbroad and misplaced.

[228] *E.g.*, Exhibit J, at 94-95.
[229] 4 Colo. Code Regs. § 723-3-3605(h); § 40-2-134, Colo. Rev. Stat.
[230] 4 Colo. Code Regs. §§ 723-3-3603(a), 3605(a)(II); Exhibit C.
[231] *Id.*, ¶ 16.
[232] Exhibit KKK, at 4.

The article discusses just one Colorado utility - Public Service – and its projected loads and resources for Summer 2026. Discussions around Summer 2026 loads have been prompted in significant part by the extended unplanned outage of coal-fired Comanche Unit 3, Colorado's newest coal-fired power plant, which has been offline since August 12, 2025. As stated in the article, CoPUC Commissioners noted Public Service's forecasted loads and resources and required the utility to quickly explore additional capacity resources. The CoPUC's actions are part of an ongoing proceeding to address the impacts of Comanche Unit 3's unavailability, including requiring Public Service to fully explain its plan for meeting forecasted load for the summer months of 2026 through 2027. As noted in the RTO Insider article, there are various strategies available to Public Service to increase capacity, and these include market purchases, unit extensions and uprates, extensions of power purchase agreements, the acquisition or acceleration of additional generation resources, pre-construction development assets, and demand response.

The Department's citation to a single news article regarding one Colorado utility is not substantial evidence of an emergency under Section 202(c). The Renewed Order provides no explanation of why concerns raised in ongoing discussions with a utility would justify continued operation of Craig Unit 1. This is particularly true where the Department disregards the CoPUC's other conclusions regarding system reliability after Craig Unit 1's retirement.[233] The Department also disregards that the article describes discussions that are representative of the regulatory process

[233] Exhibit E, ¶ 116. The CoPUC made a factual finding "that Craig Unit 1 is not required for reliability or resource adequacy purposes . . .".

and the CoPUC's careful attention to resource adequacy issues. As demonstrated by Colorado's robust and iterative resource planning processes, the CoPUC closely monitors resource adequacy issues to ensure regulated utilities can provide reliable service. The issues described in the RTO Insider article are subject to the CoPUC's timely regulatory process; by the time the Renewed Order was issued, the CoPUC had already directed Public Service to present its full contingency plan to meet forecasted load. The Renewed Order fails to present any evidence that a capacity shortfall will occur in summer 2026, it merely references a discussion of forecasted loads and resources that the CoPUC is already taking steps to address.

ii. Tri-State and PRPA demonstrate a reliable resource portfolio after Craig Unit 1's retirement.

The extensive planning processes conducted by Tri-State and PRPA, the owners of Craig Unit 1 that have joined SPP, have ensured that the unit's retirement will not negatively impact the reliability of any of their electric grids. All of the utilities are resource adequate for the 90 days covered by the Renewed Order and none of them have expressed a need for Craig Unit 1.

Tri-State's most recent electric resource proceeding[234] concluded in August 2025 with the selection of Tri-State's preferred resource portfolio as the approved cost effective resource plan.[235] The portfolio includes the addition of 700 MW of wind and solar, 650 MW of storage, and 307 MW of gas between 2026-2031, replaces the turbines on one of Tri-State's gas plants to improve its capacity contributions, and

[234] Tri-State's planning processes encompass all states in its service territory, including Wyoming and Colorado. *See* Exhibit X, at 6.
[235] Exhibit E, ¶ 90.

maintains the retirement dates of three coal plants (including Craig Unit 1).[236] Tri-State demonstrated that the portfolio meets all reliability metrics, and avoids costly transmission upgrades required by other analyzed portfolios.[237] Tri-State remains in a capacity-long position until 2030 but has planned on the above resource acquisitions to ensure reliability as its coal units retire in 2025, 2028, and 2030 and to maintain progress toward emissions reductions.[238]

Tri-State supported each of the considered resource portfolios with two levels of rigorous reliability metric checks. The first level, intended to meet industry standards, required each portfolio's satisfaction of: (1) the target planning reserve margin for each year in the resource acquisition period, or 22% transitioning to 30.5% in 2028; (2) a Loss of Load Hours maximum of 1 day in 10 years and a maximum of 2.4 hours annually; and (3) an Expected Unserved Energy maximum of less than or equal to 0.4 Gigawatt hours ("GWh") annually.[239] The second level of reliability metrics was applied to the extreme weather event sensitivities to ensure reliable service during likely future weather events, and required that this modeled sensitivity for each portfolio resulted in: (1) no more than 12 hours of expected unserved energy during all extreme weather events modeled in the years 2026-2031; (2) no more than 3 Loss of Load Hours per each year in the years 2026-2031; and (3) an Expected Unserved Energy maximum of 20% of load in any hour.[240] Tri-State demonstrated that each

[236] Exhibit X, at 6.
[237] Exhibit J.
[238] Exhibit W (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E), at 30:15-16.
[239] Exhibit J, at 18.
[240] *Id.*; Exhibit W.

presented resource portfolio met these reliability metrics. For the portfolio approved by the CoPUC, planning reserve margins ranged from 24% in 2025 to 34% in 2031, with zero Loss of Load Hours and zero annual expected unserved energy during that period.[241]

Tri-State initially proposed the planning reserve margin targets satisfied by each portfolio through a detailed analysis of grid parameters, including the reliability needs of a system transitioning away from coal generation and toward increased reliance on renewables. ELCCs were determined for each resource type to appropriately model each resource's capacity potential for the specifics of Tri-State's system, rather than relying on nameplate capacity.[242] Incorporating these ELCCs and the reliability standard of 0.1 Loss of Load Expectation, Tri-State proposed that after the retirement of the Craig Station and the departure of certain member loads in 2028, the target planning reserve margin be 30.5%, which is considerably higher than its existing and historic reserve margin.[243] These planning reserve margins were carried through to Tri-State's portfolio approved in August 2025.[244]

In summary, every portfolio that Tri-State modeled in its most recent ERP assumed the retirement of Craig Unit 1 at the end of 2025, and every modeled portfolio met all reliability metrics, including Tri-State's approved portfolio.[245] And as

[241] Exhibit J, at 62.
[242] Exhibit OO (CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 – Attachment G-1 (Astrape Consulting, Reserve Margin and ELCC Study, Public (Aug. 2, 2023)), at 8.
[243] *Id.*
[244] Exhibit W, at 20:8-15; Exhibit E.
[245] Exhibit J, Table 7: Modeled Retirements (Portfolio 1 - NEE), at 21, Table 32: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 2 – NELG), at 35, Table 28: Modeled Retirements (Portfolio 2 – NELG), at 32, Table 49: Modeled Retirements (Portfolio 3 – FLEX), at 43, Table 70: Modeled

specifically found by the CoPUC in its decision approving Tri-State's preferred portfolio, "Craig Unit 1 is not required for reliability or resource adequacy purposes based on the record in this ERP."[246] Tri-State's two most recent ERP progress reports, filed on March 17, 2026 and June 30, 2026, confirm that it is progressing with resource contracting.[247] And in its 2026 Electric Resource Adequacy Report, filed on March 17, 2026, Tri-State demonstrates that it expects to have excess resources for years 2026 through 2035.[248] Tri-State's anticipated excess capacity ranges from 123 MW in 2026 to 95 MW in 2035.[249]

These forecasts are not changed by Tri-State's recent entry into SPP. Tri-State has explained that its assets in the Western Area Colorado Missouri ("WACM") Balancing Authority will be subject to SPP's planning reserve margin requirements.[250] Tri-State intends to compare SPP's requirement to its most recent planning reserve margin requirement and follow the more stringent of the two.[251] Tri-State has stated that entering SPP will be "key for integrating intermittent resources on a large scale and further supporting affordable and reliable operations . . ."[252]

Retirements (Portfolio 4 – FLEXSR), at 54, Table 91: Modeled Retirements (Portfolio 5 – NNG), at 75, Table 112: Modeled Retirements (Portfolio 6 – NNGSR), at 75.
[246] Exhibit E, ¶ 116.
[247] Exhibit EEE (CoPUC, Tri-State, *Notice Regarding Phase II Developments,* filed on March 17, 2026, in Proceeding No. 23A-0585E), at 3; Exhibit ZZZ (CoPUC, Tri-State, *Phase II Status Update*, filed on June 30, 2026, in Proceeding No. 23A-0585E), at 1-2.
[248] Exhibit VV, Table 1 – Load and Resources, at 4.
[249] *Id.*
[250] Exhibit Z, at 8.
[251] *Id.*
[252] *Id.*, at 14.

PRPA, though not overseen by the CoPUC, develops an Integrated Resource Plan ("IRP") to conduct long-term resource planning and ensure resource adequacy.[253] PRPA ran all of its scenarios to meet a planning reserve margin of 19.9%.[254] With its current and committed resources, PRPA has enough capacity to maintain a 19.9% planning reserve margin through 2029.[255] PRPA began commercial operation of a 150 MW solar project in 2025,[256] plans to begin a 130 MW solar project in 2027, and is beginning processes to obtain additional dispatchable capacity.[257] PRPA has no resource adequacy issues now or forecasted upon the retirement of Craig Unit 1. As shown by its annual required filing with the Colorado Energy Office ("CEO"), its capacity well exceeds forecasted demand with a total accredited capacity of 885 MW and a native load forecast of 722 MW for 2026, leading to a planning reserve margin of 25.4%.[258] PRPA's General Manager and CEO has publicly stated that the utility does "not need the Craig 1 unit because it has already replaced the energy that came from it."[259]

iii. FERC and RTO oversight ensures reliability at the regional level.

In addition to these extensive State processes developed under the States' sovereign authority, the Craig Unit 1 Owners are all overseen by a variety of authorities, acting under FERC's delegated authority. As noted above, the FPA places this authority with FERC and does not provide any authority for oversight of long-term

[253] Exhibit EE.
[254] *Id.*
[255] *Id.*
[256] PRPA, *Solar Energy* (2026).
[257] Exhibit EE, at 178.
[258] PRPA, *Worksheet Certification Form* (Apr. 28, 2025).
[259] Exhibit RR (Powell, R., *1 coal plant open amid order* (Jan. 6, 2026)), at 3.

resource planning to the Department in Section 202(c). The FERC, RTO, and State processes work together to ensure reliability, and the Renewed Order illegally intrudes on these processes without any reasonable basis.

RTOs are well recognized for their grid reliability benefits. An RTO is the most comprehensive structure operating within the bulk power system, as it typically has "oversight of centralized unit commitment, economic dispatch, coordinating over a larger, multi-utility footprint and planning transmission system expansion."[260] The general benefits of being in an RTO are increasing as localized threats, such as extreme weather, become more common, which can affect supply while also increasing demand.[261] SPP's recent western expansion makes it the first RTO spanning two interconnections.[262]

States can elect to require their utilities to join RTOs and often do so due to their additional reliability benefits. Colorado requires all its transmission utilities to join an organized wholesale market on or before January 1, 2030, in part because the legislature found that the participation of utilities in RTOs and ISOs will assist in "ensuring the resilience of the electric grid and its resistance to both natural disasters and intentional attacks."[263] Accordingly, Tri-State and PRPA have joined SPP as of April 1, 2026, and now have capacity obligations under SPP's tariff.[264]

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[260] Ahumada-Paras, M. et. al., *Grid Regionalization in the West: Reliability Benefits from Increased Cooperation in Electricity Markets and Operations* (Stanford Climate & Energy Policy Program, Aug. 2024), at 1.
[261] Clean Energy Buyers Institute, *The Benefits of New Regional Transmission Planning Entities in the U.S. West and Southeast Region* (Feb. 2023), at 4.
[262] SPP, *SPP And Member Utilities Successfully Complete Historic Western Expansion* (Apr. 2, 2026).
[263] § 40-5-108, Colo. Rev. Stat.
[264] SPP, *Open Access Transmission Tariff, Sixth Revised Volume No. 1* ("OATT"), Attachment AA (FERC e-Tariff, last viewed Apl. 27, 2026); *see also* SPP Transmittal Letter, FERC Dockets ER24-2184 and ER24-2185 (filed June 4, 2024), at 50.

SPP's resource adequacy requirements complement the primary role of the states. SPP sets a base planning reserve margin that is determined by a probabilistic loss of load expectation study, which compares resources availability to forecasted peak demand.[265] Each member of the RTO must meet the summer season and winter season resource adequacy requirement or pay for any deficient capacity.[266] After each summer and winter season, transmission providers are required to conduct an analysis to compare actual net peak demand versus the planning forecast, in order to evaluate the accuracy and consistency of the forecast.[267] Beginning January 1, 2027, entities joining in the SPP West balancing authority area must own or procure the capacity to meet the entity's seasonal non-coincident peak load plus SPP's planning reserve margin for each summer and winter season.[268] In the interim, the entities' current resource adequacy processes will apply.[269]

A Future Energy and Resource Needs Study ("FERNS") for SPP conducted by the Brattle Group found that across all five of the scenarios it ran, "resource adequacy and reliability are maintained through an hourly 5% operating reserve margin requirement during all system conditions, including the challenging weather and resource adequacy conditions captured in the [] proxy year."[270] Planning reserve margins are anticipated to significantly increase over time, and remain approximately 40% during the summer and 60% during the winter through the mid-2030s.[271]

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[265] SPP *OATT*, Att. AA § 4.
[266] *Id.* § 5.
[267] *Id.* § 12.
[268] SPP OATT, Att. AA; SPP, *see also* 195 FERC ¶ 61,015, P9 (Apr. 7, 2026).
[269] SPP Transmittal Letter, ER24-2184 & ER24-2185, at 56.
[270] The Brattle Group, *Future Energy & Resource Needs Study (FERNS)* (Mar. 2025), at 25.
[271] *Id.*

Importantly, Craig Unit 1's capacity was not factored into any of SPP's reliability assessments or considerations because the unit was expected to be retired by December 31, 2025. Thus, Craig Unit 1 is not needed for SPP to meet its reliability and resource adequacy needs.

Additionally, RTOs, including the SPP RTO, often act as balancing authorities and reliability coordinators. Reliability coordinators are the highest level of authority under NERC. They are responsible for the operation of the bulk electric system and have the operating tools, procedures, and authority to prevent or mitigate emergency operating situations.[272] Balancing authorities ensure that power system demand and supply are balanced, manage transfers of electricity and use economic dispatch to optimize the use of generating units and minimize real-time costs, and maintain operating conditions under NERC reliability standards.[273]

SPP is the reliability coordinator for Tri-State, PRPA, and Public Service.[274] SPP has been a reliability coordinator for over 20 years and has extensive operating criteria, outage coordination methodology, and emergency protocols from its operation of the eastern balancing authority.[275] SPP has a Reliability Plan that details how it monitors for and responds to an emergency.[276] Like all Reliability Coordinators, SPP has "a wide-area view, operating tools, processes and procedures to prevent or mitigate emergency operating situations in next day analysis and real-time conditions[]" and has the authority to act and instruct its members to take actions to

[272] NERC, *NERCipedia: Reliability Coordinator* (2024).
[273] Department, *How it Works: The Role of a Balancing Authority* (Apr. 17, 2023).
[274] SPP, *Western RC Services* (2026).
[275] SPP, *Operating Reliability* (2026).
[276] Exhibit HH (SPP, *SPP Reliability Plan* (Jun 2, 2025)).

preserve the integrity and reliability of the bulk electric system.[277] SPP is also now the balancing authority for Tri-State and PRPA.[278]

An energy emergency is defined by NERC, WECC, and SPP as a situation when a load serving entity has exhausted all options for obtaining capacity and can no longer provide its customers with expected energy requirements.[279] A reliability coordinator will initiate an energy emergency alert at their own request, upon the request of a balancing authority, or upon the request of a load serving entity.[280] Reliability Coordinators and balancing authorities make the decision to call or request the calling of an emergency pursuant to their emergency plans and operating procedures, and SPP has processes in place to address such conditions. Therefore, if an emergency did occur in the areas in the WECC-Rocky Mountain assessment area or SPP, there are extensive procedures in place for that emergency to be handled by the complex and comprehensive network of the utilities themselves, Reliability Coordinators, and balancing authorities without the Department overstepping and preemptively trying to

[277] *Id.*, at 6-7.
[278] SPP, *2026 RTOE SWPW Transition Plan — Market Participant* (Mar. 4, 2026); SPP, *Consolidated Balancing Authority*, SPP Portal (last viewed Apr. 27, 2026).
[279] WECC, *Standard EOP-002-2 - Capacity and Energy Emergencies* (2007); SPP, *Current Grid Conditions*, Markets & Operations (last viewed Apr. 27, 2026).
[280] *Id.* At an Energy Emergency Alert Level 1, a Balancing Authority will call on all available power supplies, regardless of economics, including from other grids, and enable demand-side resource deployments.# At an Energy Emergency Alert Level 2, a Balancing Authority will initiate demand response programs that shed load from large industrial customers that have contractually agreed to do so and will publicly appeal to customers to cut back on electricity consumption.# If the highest level of emergency, Energy Emergency Alert Level 3, is called, then Reliability Coordinators will conduct emergency operating procedures to increase transfer capabilities into the entity declaring the emergency. NERC has general emergency operating instructions that address the effects of emergencies by ensuring each transmission operator and Balancing Authority has developed plans to mitigate operating emergencies and those plans are implemented and coordinated within the reliability coordinator. Exhibit II (NERC, Emergency Operations).

solve an emergency that has not occurred and is not predicted to occur in any relevant assessment.

The Renewed Order states merely that there is an emergency in the WECC-Rocky Mountain assessment area because of a potential shortfall eight years from now. There is no evidence, and the Renewed Order cites none, that an emergency within the WECC-Rocky Mountain assessment area or SPP system could not be handled by SPP's existing procedures and the existing mix of resources available in the region upon Craig Unit 1's retirement.

E. The Renewed Order is arbitrary and capricious because it requires generation that does not best meet the claimed emergency.

Even if there were an emergency within the meaning of the FPA, which there is not, Section 202(c)(1) requires the Department to impose requirements that "will best meet the emergency and serve the public interest."[281] The Department has failed to demonstrate that delaying the retirement of Craig Unit 1 satisfies this standard, and the Renewed Order is therefore arbitrary and capricious. The Renewed Order's operating instructions do not best meet the emergency or serve the public interest. Preventing the retirement of Craig Unit 1 cannot meet the Department's claimed emergency, and even if it could, it would not be the best means to do so.

i. Directing SPP to employ economic dispatch of Craig Unit 1 is vague and does not best meet the alleged emergency.

The instruction for SPP to employ economic dispatch of Craig Unit 1 is vague. The Renewed Order does not define "economic dispatch" or specify any other

[281] 16 U.S.C. § 824a(c)(1).

parameters for how it intends SPP to dispatch the Unit. The Renewed Order also states that "Craig Unit 1 shall not be considered a capacity resource[,]"[282] but SPP does not use the term "capacity resource" in its procedures and operations, making it unclear what the Renewed Order is referring to.

In addition, the Renewed Order does not reconcile the fact that operating a unit using economic dispatch is inherently at odds with that unit being operated only in an emergency. The Energy Policy Act defines economic dispatch as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[283] Economic dispatch is standard procedure for grid operators, including SPP.[284] Emergencies necessarily require unique grid operation, which is why generation units may be dispatched to provide "Out-of-Merit Energy" during an emergency. When SPP needs to resolve a reliability issue the market system cannot solve, or an emergency condition, it will dispatch "Out-of-Merit Energy" so that a resource can produce what is necessary to address a constraint.[285] This necessarily means that the resources may be operated out of economic order.[286] The dispatch directive typically specifies the MW level a resource should produce at until the constraint can be resolved through security constrained economic dispatch.[287] Operating a unit pursuant to economic dispatch is necessarily inconsistent with

[282] Exhibit KKK, ¶¶ A, G.
[283] 42 U.S.C. § 16432(b).
[284] SPP, *Integrated Systems Scenario Detail: OOME (Out-of-Merit Energy Dispatch)*, (rev. 3.0 Apr. 24, 2013)
[285] *Id.*; SPP, *Integrated Marketplace Protocols*, Section 4.4.2.5 (Apr. 17, 2026).
[286] *See* Kim Farris, *Assorted Charge Types - SUG Presentation* (Feb. 14, 2012), at slide 12.
[287] SPP, OOME Scenario (rev. 3.0).

operating a unit to address an energy emergency. If a unit is necessary to address an emergency, it would need to be dispatched regardless of price, which does not conform to economic dispatch. The Renewed Order fails to grapple with this conflict.

Further, the Department makes no attempt to demonstrate that operating Craig Unit 1 at economic dispatch is in the public interest. Because the Renewed Order's operating instructions are vague and not aimed at meeting a specific emergency, the Department does not ensure that Craig Unit 1 only operates when necessary for an emergency, thereby unnecessarily increasing emissions and costs to customers, and rendering the Renewed Order an improper exercise of the Department's emergency authority.

The problems with the Renewed Order's operating instructions, which are the same as those in the Second Order, were demonstrated soon after the Second Order was issued. SPP has called several Resource Advisories since the Second Order was issued.[288] SPP Resource Advisories are considered normal operating conditions, and do not constitute emergency conditions.[289] According to SPP, "Resource Advisories are still considered Normal Operating Conditions, and do not require the public to conserve energy or take any action, but are issued to raise awareness of potential threats to reliability among entities responsible for operating transmission and generation facilities."[290]

[288] *See*, *e.g.*, Exhibit FFF (SPP, *Current Grid Conditions* (Apr. 20, 2026)).
[289] Exhibit GGG (SPP, *Current Grid Conditions* (Apr. 7, 2026)); SPP, *Current Grid Conditions*.
[290] SPP, *Current Grid Conditions*.

Craig Unit 1 has been called to run during a few of these Resource Advisories. Therefore, the Department's vague and improper operating instructions resulted in SPP calling on Craig Unit 1 for a reliability need that did not rise to the level of an emergency and thus was outside the scope of the Department's authority under Section 202(c).

ii. Preventing Craig Unit 1's retirement does not "meet the emergency."

It is unclear how preventing Craig Unit 1's retirement could meet the emergency that the Department alleges. The nature and extent of the claimed emergency are unclear. And even if there were a capacity shortfall in any of the states served by Craig Unit 1 or the WECC-Rocky Mountain assessment area, the Renewed Order does not provide a reasoned basis for its conclusion that the continued operation of Craig Unit 1 is the best or even a viable means of alleviating the purported shortfall.

The Department cannot demonstrate that delaying Craig Unit 1's retirement meets the emergency because the Renewed Order's emergency declaration is unclear and unsupported by the record. The Renewed Order declares there is an emergency in the WECC-Rocky Mountain assessment area.[291] However, the Renewed Order goes on to remedy this emergency by directing SPP to employ economic dispatch of Craig Unit 1, meaning that Craig Unit 1 can only meet an emergency in the SPP RTO area. The SPP RTO does not cover all the WECC-Rocky Mountain assessment area.[292] Thus, the Renewed Order's remedy does not match its declared emergency.

[291] Exhibit KKK, at 1.
[292] Exhibit WW, at 8; SPP, *SPP and Member Utilities Successfully Complete Historic Western Expansion* (Apl. 2, 2026).

The Renewed Order also fails to demonstrate that there is a resource shortfall imminent and specific enough to require the continued operation of any particular resource. It is unclear how Craig Unit 1 could meet the Department's alleged emergency, regardless of how the Renewed Order's emergency determination is interpreted.

iii. Delaying the retirement of Craig Unit 1 does not "best" meet the Department's purported emergency.

Even if delaying the retirement of Craig Unit 1 could meet the non-existent alleged emergency in the WECC-Rocky Mountain assessment area, the Department has provided no explanation of how that resource would best meet such an emergency. "Best" means "that which is 'most advantageous'" or "excelling all others."[293]

The Renewed Order, and the materials upon which it relies, offer no facts that would support a determination that Craig Unit 1 is the "most advantageous" way to address the alleged emergency. Even if the Renewed Order had successfully described an emergency scenario for the regions served by Craig Unit 1 or the WECC-Rocky Mountain assessment area, the Department has not provided any specific evidence or reasoning explaining why requiring Craig Unit 1 to be available to operate is the most advantageous way to meet the scenario. Other orders issued by the Department in 2025 suffer from the same flaw, as the Congressional Research Service identified in July 2025, noting that Orders issued to the Campbell and Eddystone units have not "identified reliability risks specifically associated with the retirement of the power

[293] *Entergy Corp.*, 556 U.S. at 218 (quoting Webster's New International Dictionary 258 (2d ed.1953)); *Best*, Merriam-Webster Dictionary (Jan. 25, 2026).

plants in question at the time they approved those retirements."[294] In this respect, the Department's exercise of its emergency authority in 2025 departs markedly from past uses of Section 202(c) and from the Department's regulations implementing Section 202(c). Those regulations specify that: "[a]ctions under this authority are envisioned as meeting a specific inadequate power supply situation."[295] The Department's 2026 Section 202(c) orders have not remedied this deficiency.

The definition of "best" includes "excelling all others," which requires a comparative judgment that there are no better alternatives. This means the Department must consider alternatives and choose the alternative that is most advantageous to meet the emergency the Department has identified. The Department need not consider every conceivable alternative, but it must consider alternatives within the ambit of the existing policy as well as alternatives which are significant and viable or obvious.[296]

The Department's regulations specify information the Department must consider in deciding how to best address an emergency in a Section 202(c) order. This includes conservation or load reduction actions, efforts to obtain additional power through voluntary means, available imports, demand response, and behind the meter generation resources.[297] The Renewed Order considers none of these alternatives. Nor

[294] Exhibit T (Congressional Research Service, Federal Power Act: The Department of Energy's Emergency Authority (June 12, 2025)), at 5-6.
[295] 10 C.F.R. § 205.371.
[296] *See Dep't of Homeland Sec.*, 591 U.S. at 30 (failure to consider alternative was arbitrary and capricious); *see also Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 51 (must consider alternatives "within the ambit of the existing [standard]").
[297] 10 C.F.R. § 205.373(g)-(h). While this information is specifically required when a utility applies for a 202(c) order, it illustrates the types of information that is relevant to an alternatives analysis.

does it explain whether less burdensome measures were considered or exhausted before invoking the Department's emergency authority. Indeed, the Renewed Order never quantifies the extent of the emergency it purports to identify within Colorado or any of the states served by Craig Unit 1, making a meaningful alternatives analysis impossible. To satisfy Section 202(c)(1)'s requirement that the ordered solution best meet the emergency, the Renewed Order must address why the resources that make up the excess planned reserve margins could not meet the alleged emergency.

The Craig Unit 1 Owners chose to retire Craig Unit 1 for economic reasons.[298] And because the unit was set to retire, Craig Unit 1 has not had major maintenance since 2019;[299] it is also 45-years-old, beyond the typical economic design life of a coal burning generator and near the end of a generator's typical operational life.[300] Keeping Craig Unit 1 running is more costly now because of the deferred maintenance costs in addition to costs for fuel and continued operations.[301] Tri-State and PRPA expressed these concerns in their second request for rehearing, stating that "Craig Unit 1 is an older, uneconomic unit" that has experienced years of prudently deferred maintenance and therefore faces particularly high costs to restore and maintain operations compared to possible alternatives."[302] Colorado's understanding is that, since the issuance of the Original Order, Tri-State has had to expend costs on

[298] Tri-State, *Craig Station owners, regulators and environmental groups reach agreement on proposed revisions to Colorado regional haze plan* (Sept. 1, 2016).
[299] Exhibit B, ¶ 38.
[300] Grid Strategies, *The Economic Cost of a DOE Mandate for the Craig Unit 1 Coal-Burning Generator to Continue Operating* (Dec. 2025), at 2.
[301] Exhibit D, ¶¶ 13-15.
[302] Exhibit MMM, at 40.

maintenance and staffing.[303] These costs are currently unknown but expected to be significant, and will continue needlessly as long as the Department continues to prevent Craig Unit 1's retirement. There will also be additional costs every time SPP dispatches Craig Unit 1. Tri-State and PRPA have already stated that the costs of compliance with the orders "fall directly on their members and customers" and that the Original Order "impose[d] additional costs to Tri-State's membership and the communities served by Platte River."[304] In their Request for Rehearing of the Original Order, Tri-State and PRPA asserted that keeping Craig Unit 1 is not a best option because their members and customers will have to pay the costs associated with Craig Unit 1 even though "neither Tri-State nor Platte River are experiencing these shortages and not all the members and customers served by Tri-State and Platte River are located in the region identified by the Order."[305] One analysis estimates the annual gross cost of keeping Craig Unit 1 operational to be over $79 million.[306]

Complicating the fuel issue, Tri-State did not plan on continuing to acquire or use coal for Craig Unit 1 due to its scheduled retirement. Craig Station is supplied with coal from the Colowyo Mine, which ceased coal production at the end of 2025.[307] Two of the Colowyo Mine pits are in the final reclamation stage, and the third pit transitioned to reclamation on October 15, 2025.[308] Tri-State obtained enough coal to

[303] *See* Exhibit B, ¶ 38.
[304] Exhibit UU, at 2.
[305] *Id.*, at 5.
[306] Wannier, G., et al., *Unpacking the Cost of 202(c) Orders: Facility-Specific Cost Estimates and Methodological Approach* (June 8, 2026).
[307] Jaffe, M., *Tri-State expects federal order to keep coal-fired power plant in northwestern Colorado running* (Nov. 14, 2025).
[308] Tri-State, *Colowyo Mine to conclude coal production in 2025, transitioning to full reclamation* (Aug. 7, 2025); Weiser, C., *Colowyo coal mine near Craig lays off 133 workers as mine closes* (Nov. 26, 2025);

fuel Craig Units 2 and 3 through their planned retirement dates in 2028 but did not expect to need coal to power Craig Unit 1.[309] If Tri-State needs to use coal acquired to fuel Craig Units 2 and 3 to unexpectedly fuel Craig Unit 1, it will likely not have enough supply to also fuel the other units.[310] Tri-State would then have to buy more expensive, and possibly dirtier, coal from another source.[311]

In addition, coal generation is generally more costly than other generation resources.[312] The inefficiency of running a coal plant makes it uneconomic and is the main reason that Craig Unit 1 (and eventually, the rest of Craig Station) was slated for retirement. In fact, the CoPUC approved coal fired generating unit retirements to be replaced with lower cost wind, solar, and use of gas as a capacity resource because wind and solar were the lowest cost resources available and it was cheaper to add new renewables, storage and gas generation to the system and retire coal units.[313]

WarnTracker.com, *1 WARN Layoff Notice for ColoWyo Coal Company LP on Nov 2025* (2025); Exhibit MMM, at 8.

[309] Exhibit MMM, at 8.

[310] *See generally id.*

[311] *See* Exhibit B, ¶ 36.

[312] Weiser, C., *Colowyo coal mine near Craig lays off 133 workers as mine closes* (Nov. 26, 2025). A report by Grid Strategies found that ratepayer costs could exceed $3 billion per year if the Department mandates that all of the fossil power plants scheduled to retire between the time the report was published in August 2025 and the end of 2028 remain open. Grid Strategies asserts that the Department is ignoring the careful planning of states and utilities and "overriding cost-minimizing retirement decisions that have been made by state utility regulators and merchant power plant owners based on extensive information regarding the cost, performance, condition, and need for each plant." *see also* Grid Strategies, LLC, *The Cost of Federal Mandates to Retain Fossil-Burning Power Plants* (Aug. 2025), at 3; Exhibit O, which cost a staggering $29 million over the first 38 days; Solomon, M., et al., *Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment* (Jan. 2023), at 1-2 (a report by Energy Innovation found that "99[%] of all coal-fired plants in the U.S. are more expensive to operate on a forward looking basis than the all-in cost of renewable energy projects," and that "all but one of the country's 210 coal plants are more expensive to operate than either new wind or solar.").

[313] CoPUC, Decision No. C18-0761, issued on September 10, 2018, in Proceeding No. 16A-0396E, ¶ 103.

Coal generation also does not guarantee reliability, which further emphasizes that Craig Unit 1 does not best meet any emergency. For example, Unit 18 of the R.M. Schahfer Generating Station has been in a forced outage since July 9, 2025, after experiencing another forced outage from February 16, 2025 to June 23, 2025.[314] The unit is not expected to return to service until the third quarter of 2026.[315] Yet, despite the unit being offline, the Department issued an order requiring it to remain available on December 23, 2025, and has re-issued two more orders since then.[316] Additionally, the newest large coal-fired plant in the U.S. suffered an outage in fall of 2025 and will now be offline until March 2027.[317] This is the second time that plant has been unable to operate for a year or more. The unreliability of fossil fuel generation was demonstrated during Winter Storm Fern in late January 2026, where "renewable energy greatly exceeded the output that grid operators had expected . . . while coal and gas generators fell short."[318] This was primarily because of generator outages and derates, which impact fossil fuel fired generation more frequently than other generation resources.[319]

Finally, Craig Unit 1's long ramp up time, approximately two days, makes it particularly unhelpful in addressing short term and unexpected resource needs. It is Colorado's understanding that when addressing a situation such as SPP's designated

[314] *Id.*
[315] Howland, E., *Power plants under DOE emergency orders are producing way less energy than before* (June 23, 2026).
[316] Exhibit S; Exhibit AAA; Exhibit RRR.
[317] Institute for Energy Economics and Financial Analysis, *Newest big U.S. coal-plant offline until 2027* (Oct. 7, 2025).
[318] Goggin, M., *Winter Storm Fern Shows the Value of Transmission and Diverse Generation* (Mar. 25, 2026), at 1.
[319] *See id.*

Resource Advisories, it is preferable to use units that can be called up quickly in order to efficiently address potential short-term concerns for peak hours. The problem with this long ramp up time is demonstrated by the minimal usage of Craig Unit 1 over the seven-month period since the Original Order was issued. Craig Unit 1 has only run for a few of the times that SPP has called Resource Advisories and is generally not well suited to respond quickly to the changing demand needs that give rise to these advisories.

These facts illustrate a clear pattern: coal is not the first choice when considering reliable, affordable generation. And the Renewed Order contains no facts (either in its text or in the cited materials) that supports any determination that ordering continued availability and operation of an off-line coal unit is a reasonable response to a perceived emergency, much less "best meets" such an emergency. This is especially concerning given that Craig Unit 1's continued operation will also prevent the use of solar electricity generated by a newly added solar Axial Basin generating facility in Moffat County due to limited transmission capacity.[320] The Department does not explain how use of Craig Unit 1 is the best means to address an alleged energy shortfall when its use curtails use of other sources of power.

Given the cost of operating Craig Unit 1 and questions of reliability surrounding coal plants generally, the Department has failed to demonstrate that Craig Unit 1's continued operation "best meets the emergency" and therefore the Renewed Order is arbitrary and capricious.

[320] Exhibit UU, at 7.

F. The Renewed Order's Terms Fail to Comply with Statutory Requirements.

The Renewed Order fails to comply with Sections 202(c)(2) and 202(c)(4)(b) of the FPA, and Section 103(b) of the Department Organization Act.

i. The Renewed Order violates Section 202(c)(2) because it fails to ensure consistency with federal and State environmental laws and fails to minimize adverse environmental impacts.

Section 202(c)(2) imposes mandatory duties on the Department if a Section 202(c) order "may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation[.]"[321] The Renewed Order explicitly conflicts with the environmental laws and regulations that apply to the Craig Station Unit 1 Owners, and may also result in additional conflicts with environmental laws and regulations that apply to the State of Colorado.[322] The Department failed to comply with these requirements, rendering the Renewed Order illegal.

a. The Renewed Order directly conflicts with federal and State laws requiring Craig Unit 1 to close by December 31, 2025.

The Renewed Order directly conflicts with federal and State environmental laws and regulations that require the closure of Craig Unit 1 by December 31, 2025. These include the Air Commission's Regulation Number 23, Colorado's Regional Haze SIP adopted pursuant to the federal Clean Air Act, and Tri-State's operating permit issued pursuant to Title V of the federal Clean Air Act.[323]

[321] 16 U.S.C. § 824a(c)(2) (emphasis added).
[322] *See* Exhibit B.
[323] *Id.*

The Air Commission (with the Craig Unit 1 owners' consent) adopted the December 31, 2025 closure date into State law through Regulation Number 23, which regulates regional haze.[324] The EPA then approved this closure date into federal law when it approved Colorado's Regional Haze SIP in 2018.[325] In addition, Craig Unit 1 is a major source of air pollution[326] and therefore requires, and operates under, an operating permit issued pursuant to Title V of the federal Clean Air Act.[327] A Title V permit includes emissions limits, operational requirements, reporting obligations, and other requirements to ensure the safe and environmentally responsible operation of major sources. Condition 1.10 of Craig Unit 1's operating permit specifies that the Unit must close on or before December 31, 2025.[328]

In addition, the Colorado Legislature directed the Air Commission to adopt rules to help meet statewide statutory GHG reduction goals.[329] The Renewed Order's direction for continued availability and operation of Craig Unit 1 may restrict Colorado's ability to meet these statutory goals.

Thus, by ordering the Craig Station owners to return Craig Unit 1 to service and to be available to operate beyond the December 31, 2025, closure date, the Renewed Order directs the owners to violate both State and federal law and is subject to the requirements of Section 202(c)(2).

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[324] *See* 5 Colo. Code Reg. § 1001-27:A.IV.D.
[325] Air Plan Disapproval; Colorado; Regional Haze Plan for the Second Implementation Period, 91 Fed. Reg. 3048, 3049, fn. 9 (Jan. 26, 2026); EPA, *EPA Approved Statues and Regulations in the Colorado SIP* (Jan. 6, 2026); 83 Fed. Reg. 31332 (July 5, 2018).
[326] Craig Station is a major source and Craig Unit 1, by volume of pollution emitted, is itself a major source. Exhibit B, ¶ 32; Exhibit KK (Division, *Operating Permit No. 96OPMF155* (July 1, 2021));
[327] *See* Exhibit KK; 42 U.S.C. § 7661a(a).
[328] *See* Exhibit KK, at 25.
[329] *See* § 25-7-105(1)(e), Colo. Rev. Stat.; Exhibit B, ¶ 34; § 25-7-102(2)(g), Colo. Rev. Stat.

b. The Renewed Order does not comply with Section 202(c)(2).

Because the Renewed Order conflicts with State and federal environmental laws, the Department was required to ensure that the Renewed Order: 1) " requires generation, delivery, interchange, or transmission of electric energy *only* during hours necessary to meet the emergency and serve the public interest;" 2) "to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation;" and 3) "minimizes any adverse environmental impacts."[330] The Department's Renewed Order contains no conditions or instructions that meet these requirements.

First, by referring to the "hours" necessary to meet the emergency, Congress placed a high burden on the Department to demonstrate that the remedy provided in a Section 202(c) order is narrowly tailored to the specifics of the emergency that the order is designed to address. Even if the Department had identified a true emergency (which it has not), the FPA authorizes the Department to compel generation only when an emergency shortage of electric energy would occur absent operation of Craig Unit 1 specifically.[331] The Department's Renewed Order merely states that "SPP is directed to take every step to employ economic dispatch of Craig Unit 1 to minimize costs to ratepayers."[332] The Renewed Order's terms fail to require operation "only during the hours necessary to meet the emergency" described by the Renewed Order

[330] 16 U.S.C § 824a(c)(2) (emphasis added).
[331] *Id.*; *see, e.g.*, Department, Order No. 202-17-4, *Summary of Findings* (Sept. 14, 2017), at 9 ("authorizing operation of" units subject to emergency order "only when called upon . . . for reliability purposes," according to "dispatch methodology" approved by Department.).
[332] Exhibit KKK, ¶ A.

and violates Section 202(c)(2) because the Renewed Order does not establish any limited hours for SPP to follow when dispatching Craig Unit 1.

The Renewed Order does not define economic dispatch or specify how it intends SPP to dispatch Craig Unit 1. By leaving the dispatch of Craig Unit 1 entirely in the hands of SPP, the Department is failing to properly limit operation as required by Section 202(c). Without a clearly defined emergency, SPP has no standards to determine under what circumstances they should require the continued operation of Craig Unit 1. The premise for such continued operation is the energy "emergency" articulated in the Renewed Order, but it is impossible to know what conditions require Craig Unit 1 to operate by reading the Renewed Order.[333] Orders issued by the Department prior to 2025 demonstrate that the Department is capable of including appropriate limiting conditions in Section 202(c) orders. For example, in 2022, the Department issued an order in response to periods of extreme heat, drought conditions, and threat of wildfires that were expected to occur over several days and threaten the reliable operation of the bulk electric power system in California. That order directed the Balancing Authority of Northern California to dispatch specific units only "under the following conditions: the issuance and continuance of an Energy Emergency Alert Level[ ] 2 condition or greater between the hours of 14:00 Pacific Time and 22:00 Pacific Time after exhausting all reasonably and practically available

[333] Indeed, the Order contains confusing and contradictory instructions regarding the unit's operations, stating both that "Craig Unit 1 shall not be considered a capacity resource" and that its "continuous operation" is required. Exhibit KKK, at 1, ¶ G. Presumably, this means that the unit may only be called up by WAPA or SPP when there is an actual supply shortage that existing resources cannot meet. But if that is the intent, it is not clear from the face of the Order.

resources."[334] Although Section 202(c)(2) requires the Department to include limiting conditions in the Renewed Order as well, it chose not to, and that choice is contrary to law.

Second, Section 202(c)(2) requires that where an order may result in a conflict with environmental law or regulation, it must "to the maximum extent practicable, [be] consistent with any applicable Federal, State or local environmental laws." The Renewed Order contains no analysis of the plant's environmental obligations and no operational criteria established to minimize impacts. The Renewed Order merely states that "operations of Craig Unit 1 must comply with applicable environmental requirements… to the maximum extent feasible while operating consistent with the emergency conditions."[335] Further, the Renewed Order's acknowledgement that it "does not provide relief from any obligation to pay fees, or purchase offsets or allowances for emissions[,]"[336] does not alleviate those deficiencies.

There are numerous environmental requirements that are affected by the continued operation of the Craig Unit 1 facility, but the Department failed to identify mechanisms to allow Craig Unit 1 to remain available or operate while minimizing conflicts with these requirements. As discussed further in Section V.G.iii., the Department also did not consult with the State of Colorado, including its

[334] Department, Order No. 202-22-2 (Sept. 4, 2002), at 4; *see also Letter from Kevin Kolevar, Director, Office of Electricity Delivery and Energy Reliability to Robert Driscoll, CEO, Mirant Mid-Atlantic, LLC* (May 31, 2007) (Letter from the Department describing the emissions limitations that a utility should follow when complying with a 202(c) order.); Department, Order No. 202-17-1 (Apr. 14, 2017) (202(c) Order from the Department instructing SPP to adopt a temporary operating guide and comply with additional operating requirements set out in an EPA compliance order).
[335] Exhibit KKK, ¶ C.
[336] *Id.*

environmental regulators, who could have advised on ways to minimize impacts.[337] The Renewed Order does not reference or discuss the applicable environmental laws and regulations impacted by the Renewed Order, revealing the Department's failure to analyze these requirements to ensure compliance with environmental standards.

In particular, the Renewed Order fails to reflect any consideration of interactions with the federal Clean Air Act Regional Haze program[338] or National Ambient Air Quality Standards ("NAAQS") attainment and permitting programs. The Regional Haze program requires states to reduce emissions of NOx, SO_2, and PM from sources that affect Class I federally protected areas.[339] States must conduct detailed and expensive analyses, and based on the results of those analyses, impose federally enforceable controls and emission limits upon the largest and most impactful sources of haze pollutants.[340] The federal Clean Air Act, through the NAAQS attainment and permitting programs, also directs states to achieve and maintain air quality standards for certain pollutants, including NOx, SO_2, and PM.[341] The Department does not appear to have conducted any analysis of the impact keeping Craig Unit 1 operational may have on sources' and Colorado's ability to comply with either of these programs.

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[337] Exhibit B, ¶¶ 10, 37-39; *see also* Section 103 of the Department of Energy Organization Act, 42 U.S.C. § 7113 (requiring the Department to give due consideration to the needs of states when proposing any action that conflicts with a state energy plan, and to attempt to resolve conflicts through consultations with appropriate state officials). The Order plainly conflicts with Tri-State's decision-making process, the CoPUC's approved ERPs, the EPA-approved Regional Haze SIP, and Air Commission's Regulation Number 23.

[338] EPA recently disapproved Colorado's Regional Haze Plan for Round 2 (which does not involve Craig Unit 1) by, in part, pointing to this Order. 91 Fed. Reg. at 3049, fn. 9 (Jan. 26, 2026). While Colorado maintains that EPA's action was improper, and that its Regional Haze SIP currently meets federal requirements, it does reveal that EPA considers Craig Unit 1 relevant to Colorado's compliance with Regional Haze requirements now and in the future. The federal government must, but fails to, take a consistent position in the Regional Haze SIP disapproval and the Order as it relates to Craig Unit 1.

[339] *See* 42 U.S.C. §§ 7491, 7492; *see also* implementing regulations at 40 C.F.R. § 51.300-309.

[340] *Id.*

[341] *See, e.g.*, 42 U.S.C. §§ 7409, 7410.

The Renewed Order gives no guidance as to whether it creates conflicts with either of these requirements and, if it does, how to navigate them.

Accordingly, the Renewed Order violates the Department's statutory obligation to "ensure" the maximum feasible compliance with applicable environmental standards.[342] This obligation requires the Department to offer some discrete guidance as to the unit's operations, rather than merely parroting the statutory text. This lack of detail also makes it impossible for Colorado's environmental regulators to know what operational activities are excused from environmental compliance by the Renewed Order, increasing the complexity and burdens associated with any state enforcement actions.

Third, Section 202(c)(2) requires the Department to minimize the adverse environmental impacts of the Renewed Order, which the Renewed Order fails to do. This mandate is textually and substantively distinct from the Department's (also unfulfilled) obligation to ensure maximum practicable compliance with environmental standards. By failing to include a sufficient or legal description of the purported emergency, this Renewed Order authorizes Craig Unit 1 to generate electricity and pollute beyond any emergency needs, thereby increasing the environmental impacts that, by law, the Renewed Order must minimize. When Craig Unit 1 operates, it emits NOx, SO_2, fine PM, GHG emissions, HAPs, and other harmful pollutants.[343] The Renewed Order includes no measures to mitigate impacts when compliance with environmental standards proves impracticable, even though those types of measures

[342] 16 U.S.C. § 824a(c)(2) (emphasis added).
[343] Exhibit B, ¶ 18.

have been routinely included in past orders.[344] At a minimum, the statute requires the Department to include sufficiently detailed reporting obligations to ascertain what impacts result from emergency operations; without such reporting, the Department has no ability to "ensure" that adverse impacts are minimized.[345] The Renewed Order here instead merely requires "such additional information" as the Department, in the future, may (or may not) "request[] . . . from time to time."[346] That possibility of future, unspecified information gathering cannot satisfy the statute's demand that the Department "ensure" that its Renewed Order minimizes environmental impacts.[347]

Similarly, the Renewed Order does not address or assess mechanisms to minimize the pollution from Craig Unit 1 associated with its operation in response to the Renewed Order. It also does not address or assess the environmental impacts associated with the acquisition and transport of additional coal that may be necessary to facilitate Unit 1's operation and contains no limitations on the type of coal that may be used so as to minimize the impacts of any new emissions. Not all coal is inherently compatible with the units at the Craig Station, and depending on where new coal is sourced from, there could be significant emissions and costs associated

[344] *See, e.g.*, Department, Order No. 202-17-4 (Sept. 14, 2017), at 2 (permitting non-compliant operation only during specified hours, and requiring exhaustion of "all reasonably and practicably available resources," including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions); Department, Order No. 202-22-4 (Dec. 12, 2022) (requiring "reasonable measures to inform affected communities" of non-compliant operations).
[345] *See, e.g.*, Department, Order No. 202-24-1 (Oct. 13, 2024), at 4-5 (requiring detailed data on emissions of pollutants).
[346] Exhibit KKK, ¶ D.
[347] 16 U.S.C. § 824a(c)(2).

with the distances required to import that coal.[348] Nor are these impacts addressed by the Department's cursory instruction to Tri-State to comply with applicable environmental requirements "to the maximum extent feasible."[349] Because the Department made no attempt to address the requirements of Section 202(c)(2), the Renewed Order is unlawful.

ii. The Renewed Order violates Section 202(c)(4)(B) because the Department failed to consult with the primary federal agency with expertise in the relevant environmental interests.

Finally, the Renewed Order provides no indication that the Department has, as required by Section 202(c)(4)(B), "consult[ed] with the primary Federal agency with expertise in the environmental interest protected" by any laws with which the renewed or re-issued order may conflict.[350] Nor does the Renewed Order include any conditions such federal agency "determines necessary to minimize any adverse environmental impacts to the extent practicable" or a public explanation of the Department's determination that such conditions "would prevent the order from adequately addressing the emergency."[351]

The Renewed Order serves as a renewal of the Second and Original Orders on the claimed basis that "[t]he emergency conditions that necessitated the issuance of [the Second Order] continue[.]"[352] As stated above, the Renewed Order conflicts with several federal and State environmental laws.[353] The EPA is the federal agency with

[348] Exhibit B, ¶¶ 37-38.
[349] Exhibit KKK, ¶ C.
[350] *See* 16 U.S.C. § 824a(c)(4)(B).
[351] *See id.*
[352] Exhibit KKK, at 3.
[353] *See supra*, Section F.ii.a.

expertise and authority over federal air quality regulations and approved Craig Unit 1's retirement date, Colorado's Regional Haze SIP, and Craig Stations' Title V Permit, making them federally enforceable. Therefore, the Department was required to consult with, at a minimum, the EPA prior to issuing the Renewed Order.

The Renewed Order makes no mention of this consultation requirement and provides no evidence of consultation with the primary federal agency, as the Department has in other Section 202(c) orders.[354] If the Department has failed to consult and procure any required conditions from the relevant federal agency, it has violated the statute. If it has received and declined conditions but refused to disclose them or provide any explanation of why the Department believes such conditions would prevent the order from adequately addressing the claimed emergency, that too violates the statute.

For these reasons, the Renewed Order fails to comply with the Department's obligations under Section 202(c)(2) and should be withdrawn.

iii. The Renewed Order violates Section 103 of the Department Organization Act because the Department failed to consult with the appropriate Colorado officials.

The Renewed Order violates Section 103 of the Department Organization Act, which requires:

[354] *See, e.g.*, Exhibit U, at 8 ("Pursuant to [S]ection 202(c)(4)(B) of the FPA, the Department has consulted with the primary [f]ederal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order."); Exhibit PP, at 8 ("Pursuant to [S]ection 202(c)(4)(B) of the FPA, the Department has consulted with the primary [f]ederal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.").

> Whenever any proposed action by the Department conflicts with the energy plan of any State, the Department shall give due consideration to the needs of such State, and where practicable shall attempt to resolve such conflict through consultations with appropriate State officials.[355]

The Department has acknowledged that Section 103 of the Department Organization Act is applicable to the Department in this situation. The Department argued in the Campbell case that the provision did not apply to the Original Campbell Order because consultation is not practicable in an emergency situation.[356] However, the Department has now had 180 days since the issuance of the Original Order to comply with Section 103 of the Department Organization Act, and it has failed to do so.

The Renewed Order conflicts with Colorado's statewide GHG pollution reduction targets[357] and interferes with Tri-State's plan to reduce GHG emissions 80 percent by 2030,[358] as reflected in the CoPUC's approval of Tri-State's ERP, which included the retirement of Craig Unit 1 by December 31, 2025. The Department also did not make any attempt to give "due consideration" to the needs of Colorado, nor did it make any attempt to consult with the CoPUC or Colorado Air Pollution Control Division.[359]

[355] 42 U.S.C. § 7113.
[356] The Department, *Order No. 202-25-3B* (Sep. 8, 2025).
[357] § 25-7-102(2)(g)(I), Colo. Rev. Stat.
[358] § 25-7-105(1)(e)(VIII)(I), Colo. Rev. Stat.
[359] Exhibit B; Exhibit C.

G. The Renewed Order is designed to support the federal administration's policy goal of propping up the coal industry, making it an arbitrary and capricious pretext.

Agency action is arbitrary and capricious when it rests on a "pretextual" reason that is "incongruent with what the record reveals about the agency's priorities and decision-making process."[360] Agency decisions that feature "unjustifiable bias or partisanship are precisely the types of agency actions that 'would work a violation of the arbitrary-and-capricious standard.'"[361] Here, the record demonstrates that there is no evidence of an energy emergency within the meaning of Section 202(c) that would support issuance of the Renewed Order. Instead, the Renewed Order is a transparent attempt to favor the Trump administration's preferred energy source and revive the coal industry. Because the Renewed Order is pretextual and divorced from any actual emergency, the Renewed Order violates the law and must be withdrawn.

i. The federal administration intends to promote coal.

Over the course of 2025 and 2026, the Department and the President have made clear that they are using Section 202(c) orders to prevent coal-fired generating plants from retiring, simply because the current administration prefers coal and other fossil fuel generation. On his first day in office, the President declared a "National Energy Emergency" and identified coal as one of his preferred energy resources.[362] The President later directed the Department to "streamline" its use of emergency orders, explaining that his goal was to "revitaliz[e] America's big beautiful coal

[360] *Dep't of Commerce*, 588 U.S. at 785.
[361] *Level the Playing Field*, 961 F.3d at 464 (quoting *Hagelin v. FEC*, 411 F.3d 237, 242 (D.C. Cir. 2005)).
[362] Exec. Order 14156, 90 Fed. Reg. 8433, 8434 (Jan. 20, 2025), Sec. 8(a).

industry to support grid stability and American jobs."[363] In July, Secretary Chris Wright stated "'I think our biggest impact by far is going to be — there are like 40 coal plants that are supposed to close this year — and our biggest impact is going to be to stop the closure of most of those[.]'"[364]

Both the Department and President Trump have publicly acknowledged that their goal is to regulate long-term resource adequacy and mandate coal generation. Secretary Wright has stated that "[t]he goal [of the recent Section 202(c) orders] is to stop the political closure of coal plants."[365] The "Clean Beautiful Coal" Executive Order directed the Department to "identify regions where coal-powered infrastructure is available and suitable for supporting [artificial intelligence ("AI")] Data centers; assess the market, legal and technological potential for expanding coal-based infrastructure to power data centers to meet the electricity needs of AI . . ."[366] Most recently, the President received a trophy proclaiming him the "Undisputed Champion of Beautiful Clean Coal" after issuing yet another executive order, this time ordering the Department of War to purchase coal power.[367]

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[363] The White House, *Fact Sheet: President Donald J. Trump Strengthens the Reliability and Security of the United States Electric Grid* (Apr. 8, 2025); *see also* New York Times, Trump Signs Orders Aimed at Reviving a Struggling Coal Industry, April 8, 2025); Exec. Order 14261, Reinvigorating American's Beautiful Clean Coal Industry and Amending Executive Order 14241, 90 Fed. Reg. 15517 (April 14, 2025); Exec. Order 14260, Protecting American Energy from State Overreach, 90 Fed. Reg. 15513 (April 14, 2025); Regulatory Relief for Certain Stationary Sources To Promote American Energy, 90 Fed. Reg. 16777 (April 21, 2025).
[364] Young, C., *Energy Secretary Chris Wright: Future of U.S. coal is 'long and bright'* (July 7, 2025).
[365] Exhibit III, (Brown, C., Plumer, B., *Trump Wants to Halt Almost All Coal Plant Shutdowns. It Could be Messy* (Jan. 16, 2026)), at 1.
[366] Exec. Order No. 14241, 90 Fed. Reg. 15517 (Apr. 14, 2025).
[367] Shah, S., *Coal Power is Rebounding in the U.S. Here's How it Happened* (Mar. 3, 2026); Exec. Order 14386, Strengthening United States National Defense with America's Beautiful Clean Coal Power Generation Fleet, 91 Fed. Reg. 7393 (Feb. 17, 2026).

These statements and actions demonstrate a clear intention to use coal plants to meet long-term resource adequacy needs, which exceeds the Department's Section 202(c) emergency authority.

ii. The Department's 2025 and 2026 Section 202(c) orders demonstrate a pattern of arbitrary and capricious behavior designed to carry out a policy goal.

In line with the policy goals described above, the Department has issued orders for nearly every coal plant scheduled to retire in 2025 and 2026, all for the statutory maximum of 90 days. Collectively, the Department's Section 202(c) orders have now forced seven power plants to stay open past their planned retirement dates. Each of these orders have been summarily renewed; [368] the Campbell and Eddystone Orders for the fifth time—meaning they have now been subject to an emergency order for over a year— and the remainder for the third time. None of these orders or their renewals meet the same criteria as previous orders issued pursuant to Section 202(c). Specifically, none were publicly requested by a utility;[369] none were based on an inability to comply with environmental laws; and none were responsive to or tailored to meet a specific, imminent, unexpected and temporary emergency.

The Department, Secretary Wright has confirmed that "[t]he goal [of the recent 202(c) orders] is to stop the political closure of coal plants."[370] These orders have claimed emergencies in arbitrary and changing regions, largely based on a variety of NERC assessments that describe a host of different circumstances and reach

[368] Excluding the Stanton Order, which was just issued for the first time.
[369] It is common practice for the Department to post the request of the entity requesting a specific order within that order's docket. *See, e.g.* Department, *2024 DOE 202(c) Orders* (2024); Department, *2023 DOE 202(c) Orders* (2023).
[370] Exhibit III, at 1.

varied conclusions. For example, in the Original Order for Craig Unit 1, the Department claimed an emergency in the WECC-Northwest assessment area, based on the 2024 LTRA, despite the fact that the Winter 2025-2026 NERC assessment was much more relevant for an order extending from Denver to March. In the Second and Renewed Orders, the geographic area of the claimed emergency has changed to WECC-Rocky Mountain because of realignment in the assessment areas, and yet according to the Department, the claimed "emergency" still exists in this new area, and Craig Unit 1 is still the best way to meet that emergency. The Department failed to acknowledge or explain this change. The Department is pointing to cherry picked information from each report to arbitrarily find an emergency to support a single solution (prevention of a planned coal plant retirement), even though it looked at two completely different geographic areas between the first and second report. This is evidence of arbitrary pre-judgment.

The Department consistently relies on resource assessments that are devoid of any evidence of an energy emergency. The 2026 SRA found normal risk for the MISO assessment area, which includes the Campbell, Schahfer, and Culley plants; normal risk for the Rocky Mountain assessment area, which includes Craig Unit 1; normal risk for the PJM assessment area, which includes the Eddystone plant; and normal risk for the SERC-Florida Peninsula assessment area, which includes the Stanton plant.[371] The 2026 SRA also found that a large influx of generation resources has outpaced demand and is boosting reserves, and that battery resource additions help maintain stable

[371] Exhibit NNN.

frequency on the grid.[372] And the WECC Summer 2026 Assessment found that "[a]n influx of resources, primarily solar and battery but also natural gas-fired generation, has outpaced demand and boosted reserves, easing resource adequacy concerns across the continent."[373] The program director of GridLab, a nonprofit technical consulting organization focused on the electric grid, emphasized that NERC's recent SRA and WRA indicate that there is no energy emergency.[374]

Additionally, the Department has issued Section 202(c) orders for closing coal plants in complete disregard of their condition or age. For example, the most recent Section 202(c) order to keep R.M. Schahfer Plant Units 17 and 18 running ignores the fact that Unit 18 was in a forced outage from February 16, 2025 to June 23, 2025, and then again starting on July 9, 2025. The unit is still in a forced outage and is not expected to come online until the third quarter of this year, meaning that unit has been and will be in an outage for the entire duration of the issued 202(c) orders.[375] It is unclear how a plant that barely operated throughout 2025 and was not operational at the time the Department issued its original, second, or third Section 202(c) orders could help in an alleged emergency. Similarly, when the Original Order was issued, Craig Unit 1 was in a forced outage and was not repaired until a third of the way into the period of the Original Order. And as of the time of filing this Request, it is Colorado's understanding that Craig Unit 1 is once again in a forced outage.

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[372] *Id.*
[373] Exhibit UUU, at 2.
[374] Howland, E., *DOE emergency orders are incurring additional costs. What are the benefits?* (June 25, 2026).
[375] Howland, E., *Power plants under DOE emergency orders are producing way less energy than before* (June 23, 2026).

Every single Section 202(c) order to keep a retiring coal plant online in 2025 and 2026 has been challenged. The Department has summarily denied the numerous requests for rehearing challenging each of these orders, often with no substantive explanation. Before the Culley Order was renewed, the Region President of its operating utility asked the Department to not issue another Section 202(c) order because Culley Unit 2, which is 60 years old, "will require substantial investment to support an inefficient and increasingly unreliable asset, rather than advancing affordable and reliable service for customers in southwestern Indiana."[376] The letter pointed out that over the 48 days between the issuance of the order and the letter, the unit was on outage for 26 days, available but not economically dispatched by MISO for 5, and online but limited to 45 MW due to maintenance issues for 17 days.[377] The letter also highlighted that operation beyond the expiration of the first order would require a four week or longer outage with a projected cost of $1.9 to $2.5 million to perform necessary maintenance.[378] The Department ignored this and issued a renewed Culley Order. The Department also did not substantively respond to Tri-State and PRPA's request for rehearing of the Original Order until June 24, 2026, over five months later, and in the interim issued the Second Order, followed shortly by the Renewed Order, ignoring their request that the Department work with them to find a more effective and affordable path forward to meet the Department's concerns.[379]

[376] Letter from Michael Roeder, President, Indiana Region, to the Honorable Chris Wright, Secretary for Energy (Feb. 17, 2026), at 1.
[377] *Id.*, at 2.
[378] *Id.*
[379] Exhibit UU, at 5-6.

When asked what it would take for DOE to stop issuing orders for a particular power plant, DOE asserted that it has made "individual decisions based on the particular set of facts and circumstances in each case."[380] This is clearly a misrepresentation of the Department's actions. These orders have been consistently renewed for the maximum 90-day period like clockwork, disregarding the season, the state of the power plant, opinions of the plant operators, and even the location of the plant in relation to the area for which the order calls an emergency. The Orders all cite to the President's multiple unfounded declarations of a "national energy emergency" and the Department's own Resource Adequacy report which only found potential reliability issues in 2030.[381] Further, the Orders frequently rely on the same long term NERC assessments that do not assess imminent resource adequacy, and often find that the area where DOE has declared an emergency is at normal risk.[382] The Orders also frequently ignore more relevant assessments, such as NERC's winter or summer reliability assessments, in favor of cherry picking statements from these long term reliability assessments.[383]

Together, the Department's orders demonstrate that, rather than addressing emergencies, the Department is working to prevent the retirement of coal plants across the United States as part of their larger efforts to bolster the coal industry.[384]

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[380] Lutz, M., *DOE's Alex Fitzsimmons on energy markets, AI, renewables and more* (June 5, 2026).
[381] *See, e.g.*, Exhibit OOO; Exhibit PPP; Exhibit QQQ; Exhibit RRR; Exhibit SSS.
[382] *See, e.g.*, Exhibit PP; Exhibit ZZ; Exhibit AAA; Exhibit QQQ; Exhibit SSS.
[383] *See, e.g.*, Exhibit A; Exhibit R; Exhibit S (the Department relied on NERC's 2024 Long Term Reliability Assessment instead of the 2025-2026 Winter Reliability Assessment that covered the same period as the Original Order).
[384] *See, e.g.*, The Department, Energy Department Converse First National Coal Council Meeting Under Renewed Charter, Reaffirming Coal's Role in Unleashing American Energy (Jan. 15, 2026); The Department, *Energy Department Announces $175 Million to Modernize Coal Plants, Keeping Affordable Reliable Power Online for Americans* (Feb. 11, 2026); The Department, *Fact Sheet: The Department of*

iii. Despite claims it is addressing energy emergencies, the Department is simultaneously interfering with efforts to increase generation through renewable resources.

At the same time the Department is claiming that an energy emergency justifies exercise of its Section 202(c) emergency authority, it is also working to stymie development of renewable generation sources, particularly wind and solar. It has also failed to acknowledge that Craig Unit 1's continued operation will also prevent the use of solar electricity generated by a newly added solar farm in Moffat County due to limited transmission capacity.[385]

The Department's own website explains that "wind energy offers many advantages which explains why it's one of the fastest-growing energy sources in the world[,]"[386] and that solar energy "can support household savings, energy independence, economic opportunities, grid reliability, resilience, security and affordability, and a safer planet."[387] Wind and solar energy are also extremely cost competitive with other energy sources. The most recent Levelized Cost of Energy+ Report ("LCOE Report") found that "[o]n an unsubsidized $/MWh basis, renewable energy remains the most cost-competitive form of generation."[388] Renewables are also important in a high demand scenario, as they are the "quickest-to-deploy generation resources."[389] Colorado has confirmed that wind and solar energy are low

Energy Is Ending The War On Beautiful, Clean Coal (Jan. 15, 2026); *see also* Exec. Order 14261, Reinvigorating American's Beautiful Clean Coal Industry and Amending Executive Order 14241, 90 Fed. Reg. 15517 (April 14, 2025).

[385] *See* Exhibit UU.

[386] Department, *Advantages and Challenges of Wind Energy*.

[387] Department, *Solar Energy*.

[388] Lazard LCOE, *Levelized Cost of Energy+* (June 2025), at 4.

[389] *Id.*

cost options to provide reliable electricity generation in the Northwest Colorado region, including Craig Unit 1.[390]

Despite these advantages, the federal government and the Department have been actively repressing wind, solar, and hydrogen fuel deployment. Alongside the Energy Emergency Executive Order, President Trump issued an executive memorandum ("Memo") directing federal agencies to pause the issuance of all wind energy authorizations.[391] That Memo has since been declared unlawful and vacated.[392] In addition, the One Big Beautiful Bill Act ended subsidies for wind and solar energy projects years earlier than planned.[393] The Department has also cut funding for grants that were supposed to go to projects such as hydrogen technology and upgrades to the electric grid.[394] And although the solar industry installed nearly 18 GW of new capacity in the first half of 2025, the federal administration's efforts to stymie wind and solar energy has resulted in significantly reduced solar deployment.[395]

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[390] *See* Colorado Energy Office, *Exploring Advanced Energy Solutions for Rural Colorado* (Dec. 19, 2025) (study looked at both the levelized cost of energy and the levelized cost of capacity for multiple generation options and found that solar combined with battery storage has the lowest levelized cost of electricity, and wind combined with battery storage has the lowest cost levelized net cost of capacity).
[391] Temporary Withdrawal of All Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects, 90 Fed. Reg. 8363 (Jan. 29, 2025).
[392] Judgement Ordered 12/18/2025 in *State of New York v. Trump*, 25-cv-11221-PBS (D. Mass.).
[393] Sidley, *The "One Big Beautiful Bill" Act – Navigating the New Energy Landscape* (Jul. 15, 2025); *see also* 26 U.S.C.A. § 45Y (creating wind production tax credits, passed Aug. 2022); 26 U.S.C.A. § 48E (creating solar investment tax credits, passed Aug. 2022); One Big Beautiful Bill Act, Pub. L. 119-21, Title VII, § 70512-3, 139 Stat 72 (July 4, 2025) (amending 26 U.S.C.A § 45Y and 26 U.S.C.A. § 48E to end subsidies for wind and solar projects).
[394] *See* Walton, R., *DOE cancels $7.6B in clean energy awards in states that voted against Trump* (Oct. 2, 2025); Banse, T., *Trump administration yanks funding for Northwest green hydrogen project* (Oct. 2, 2025); Kaufman, A., *Trump's cuts to billion-dollar hydrogen hubs rattle industry* (Oct. 2025).
[395] Wood Mackenzie, *Solar and storage dominate new power additions in first six months of Trump administration as federal policies drive up energy costs* (Sept. 9, 2025); Economy+Environment, *Clean Economy Works: November 2025 Analysis* (Dec. 12, 2025).

In March, the federal government announced that it will pay an energy developer almost $1 billion in taxpayers funds to cancel federal leases for two offshore wind projects, in exchange for a commitment from the company to reinvest in oil and gas projects.[396] The federal government has struck two more similar deals since then, spending roughly $2.5 billion to get companies to terminate offshore wind leases.[397] President Trump has gone as far as to admit that his "goal is to not let any windmill be built . . . They're losers."[398] In line with these policy goals, the Department of Interior has cancelled 30 onshore wind farm projects, thereby stalling around 7.5 GWs of capacity.[399] The Rural Energy for America program has also been put on hold, and forthcoming changes will discourage larger-scale solar projects.[400] Finally, the Department of Defense has refused to authorize any new onshore wind projects since August 2025, which is affecting a least 125 utility-scale wind energy projects across 25 states.[401]

As the Department has observed, "the reliability of the power grid is intrinsically a system-wide property that cannot be ensured by an individual resource or technology in that system."[402] Focusing on one technology instead of a portfolio of resource adequacy measures increases risk.[403] The Department's current single-

[396] U.S. Department of the Interior, *Interior and TotalEnergies Agree to End Offshore Wind Projects, Lowering Costs for American Families* (Mar. 23, 2023).
[397] Plumer, B., *Trump Administration to Pay $765 Million to Cancel 4 More Wind Projects* (June 17, 2026).
[398] Exhibit JJJ (Harder, A., *Exclusive: Wind projects pile up as Pentagon reviews stall* (Mar. 30, 2026)), at 3.
[399] *Id.*, at 2.
[400] Heller, M., *Trump's opposition to renewables stalls rural energy grants* (Apr. 1, 2026).
[401] Amended Compl., ¶ 18, *Renewable Northwest v. Hegseth,* No. 3:26-cv-01092-IM (D. OR.).
[402] Department, *The Future of Resource Adequacy* (Apr. 2024), at 8.
[403] *Id.*

minded focus on coal and other fossil fuels reflects a policy preference as opposed to a desire to address any actual energy emergency and constitutes an unlawful pretext.

H. The Department failed to comply with NEPA.

By requiring Craig Unit 1 to remain available beyond its planned retirement date, the Renewed Order has the potential to cause significant environmental impacts and requires evaluation under NEPA, particularly as it now seems clear the Department will continue issuing renewals regardless of the existence of an emergency.[404] Because the Department has misused its emergency authority in the Renewed Order,[405] it cannot rely on the exception to NEPA's implementing procedures that applies to emergency actions. Quite simply, there is no "emergency situation[] that demand[s] immediate action" here.[406] As demonstrated above, there is no current or imminent energy shortfall or near-term reliability emergency that justifies continued operation of Craig Unit 1.[407] Accordingly, to the extent the Department is relying on the exception for emergency actions to avoid full NEPA analysis, such reliance is contrary to law.

Moreover, the Department's NEPA implementing regulations recognize that where an action has the potential to cause significant impacts on an environmentally sensitive area, such as federally- and state-designated wilderness areas, national parks, scenic areas, and similar resources, the action is not appropriate for categorical exclusion and instead must be analyzed under NEPA.[408] Here, retirement

[404] 42 U.S.C. § 4336(b), *supra*.
[405] *See supra,* Sections V.A-H.
[406] 10 C.F.R. § 1021.103.
[407] *See supra,* Section V.C.
[408] 10 C.F.R. Part 1021, Appx. B, § B(4)(iv).

of Craig Unit 1 by December 31, 2025 is a requirement of Colorado's federally approved SIP to address the federal Clean Air Act visibility program. This program is designed to protect federally-designated areas home to sensitive ecosystems or species potentially harmed by even small increases in pollution.[409] Specifically, the Colorado Regional Haze SIP, which incorporated Craig Unit 1's retirement date in Round 1, is designed to protect national parks and wilderness areas in Colorado including Black Canyon of the Gunnison National Park, Great Sand Dunes National Park, Rocky Mountain National Park, and Mount Zirkel Wilderness Area.[410] Craig Unit 1 is located near the Mount Zirkel Wilderness Area.[411] As a result, the Department's own NEPA regulations dictate that the action was subject to NEPA review.

VI. Request For Stay

In addition to seeking rehearing, the State of Colorado moves the Department for a stay of the Renewed Order until the conclusion of judicial review.[412] The Department should also refrain from renewing the Renewed Order as currently drafted beyond its current expiration in September 2026. The Department has the authority to issue a stay under the Administrative Procedure Act and should do so where "justice so requires."[413] In deciding whether to grant a request for stay, agencies consider: (1) whether the party requesting the stay will suffer irreparable

[409] Exhibit B, ¶ 31.
[410] Exhibit MM (Division, *Colorado Visibility and Regional Haze SIP for the Twelve Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016)).
[411] 5 Colo. Code Regs. § 1001-5:F.VI. (2014).
[412] 18 C.F.R. § 385.212.
[413] 5 U.S.C. § 705.

injury without a stay; (2) whether issuing a stay may substantially harm other parties; and (3) whether a stay is in the public interest.[414]

Injuries under this standard must be actual, certain, imminent, and beyond remediation.[415] Financial injury is irreparable where no "adequate compensatory or other corrective relief will be available at a later date, in the ordinary course of litigation."[416] Environmental injury, however, "can seldom be adequately remedied by money damages and is often permanent or at least of long duration, *i.e.*, irreparable. If such injury is sufficiently likely, therefore, the balance of harms will usually favor the issuance of an injunction to protect the environment."[417]

A. Colorado and its people will suffer irreparable injury absent a stay.

Here, a stay is necessary to prevent irreparable harm to the State of Colorado. Craig Unit 1 emits dangerous air pollutants that would not otherwise occur but for the Renewed Order. Craig Unit 1's continued availability and operation increases costs, which have already been passed on to ratepayers, along with increasing pollution directly through readying activities, and indirectly through the sourcing and transportation of fuel. Even if the unit dispatches rarely, these excess pollutants

[414] *See Nken v. Holder*, 556 U.S. 418, 434, 436 (2009); *Ohio v. EPA*, 603 U.S. 279, 291 (2024); *see, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,020, at 41 (2023); *ISO New Eng. Inc.*, 178 FERC ¶ 61,063, at 13 (2022), *rev'd on other grounds sub nom. In re NTE Conn., LLC*, 26 F.4th 980, 987-88 (D.C. Cir. 2022).

[415] *Mexichem Specialty Resins, Inc. v. EPA*, 787 F.3d 544, 555 (D.C. Cir. 2015); *Wis. Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985); *ANR Pipeline Co.*, 91 FERC ¶ 61,252, at 61,887 (2000); *City of Tacoma*, 89 FERC ¶ 61,273, at 61,795 (1999) (recognizing that, absent a stay, options for "meaningful judicial review would be effectively foreclosed").

[416] *Wis. Gas Co.*, 758 F.2d at 674 (quoting *Va. Petroleum Jobbers Ass'n v. Fed. Power Comm'n*, 259 F.2d 921, 925 (D.C. Cir. 1958)); *see also In re NTE Conn., LLC*, 26 F.4th at 990-91. (Colorado refuses to concede that its residents, as ratepayers, should bear the cost of the Department's illegal actions here. Nonetheless, we assume that neither the Department nor the Craig Station owners want to bear those costs either and will seek to impose them on Coloradans.).

[417] *Amoco Prod. Co. v. Vill. of Gambell*, 480 U.S. 531, 545 (1987).

contribute to and exacerbate respiratory problems, cardiovascular issues, and other health conditions.[418] By continuing to delay the retirement of a 45-year-old coal-fired unit, the Department is causing Colorado's electric customers to be served by a more costly and less reliable and resilient electric grid. Instead of continuing to invest in and develop more reliable resources as planned, the Craig Unit 1 Owners will have to dedicate resources to repair and maintain a coal plant that is less reliable and more costly than other generation resources.

A stay would not result in harm to any other interested parties. The issuance of a stay would not harm end-use electricity consumers because there is no emergency addressed by the operation of Craig Unit 1. The lack of an actual emergency means that a stay would not disrupt the provision of electricity. Furthermore, because Tri-State had already planned for the closure of Craig Unit 1, a stay would have the effect only of relieving Tri-State of the administrative, compliance, and planning burdens imposed by the Renewed Order. On the balancing of equities, there is therefore no meaningful countervailing harm that would follow from a stay.

B. A stay is in the public interest.

There is no public interest served by the Renewed Order, and a stay will only benefit the public. First, the Renewed Order exceeds the Department's authority; it has provided no reasonable grounds to substantiate any near-term or imminent shortfall in electricity supply that would necessitate Craig Unit 1's continued

[418] Exhibit B, ¶ 26.

operation.[419] Second, a stay would protect the broader public from the costs and additional pollution produced by unnecessary operation of Craig Unit 1.

VII. Conclusion

For the reasons set forth above, the State of Colorado respectfully requests that the Department grant intervention; grant a rehearing and rescind the Renewed Order; and stay the Renewed Order.

Filed on July 24, 2026.

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[419] *See League of Women Voters v. Newby*, 838 F.3d 1, 12 (D.C. Cir. 2016) (noting that "there is a substantial public interest 'in having governmental agencies abide by the federal laws that govern their existence and operations'") (quoting *Washington v. Reno*, 35 F.3d 1093, 1103 (6th Cir. 1994)).

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Certificate of Service

This is to certify that I have duly served the foregoing, **The State of Colorado's Request for Rehearing, Motion to Intervene, and Stay Request**, upon all parties below electronically via e-mail this 24th day of July, 2026:

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State of Colorado's Exhibit List

Exhibit No.	Document Description
A	Department, Order No. 202-25-14 (Dec. 30, 2025)
B	Declaration of Josh Korth Declaration (July 22, 2026)
C	Declaration of Erin O'Neil (July 23, 2026)
D	Declaration of Joseph Pereira (July 22, 2026)
E	CoPUC, Decision No. C25-0612, issued on August 26, 2025, in Proceeding No. 23A-0585E.
F	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-2, (Tri-State, *2020 IRP/ERP,* Public (Dec. 1, 2020))
G	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Attachment BN-1 (Tri-State, *Responsible Energy Plan* (Jan. 2020)
H	Salt River Project, 2023 Integrated Systems Plan
~~I~~	Department, Order No. 202-25-7 (Aug. 20, 2025)
J	CoPUC, 120 Day ERP Implementation Report, Public, filed on April 11, 2025, in Proceeding No. 23A-0585E
K	NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024)
L	NERC, *2025-2026 Winter Reliability Assessment* (Nov. 2025)
M	Department, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (July 2025)
N	Motion to Intervene and Protective Request for Rehearing by the Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York, filed on August 6, 2025 with the Department
O	Department, Order No. 202-25-3 (May 23, 2025)
P	Department, Order No. 202-25-4 (May 30, 2025)
Q	Department, Order No. 202-25-11 (Dec. 16, 2025)
R	Department, Order No. 202-25-13 (Dec. 23, 2025)
S	Department, Order No. 202-25-12 (Dec. 23, 2025)
T	Congressional Research Service, *Federal Power Act: The Department of Energy's Emergency Authority* (June 12, 2025)
U	Department, Order No. 202-25-9 (Nov. 18, 2025)
V	Department, Order No. 202-25-8 (Aug. 28, 2025)
W	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E
X	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 (Tri-State, 2023 ERP Phase I, Rev. 2 (Apr. 22, 2024)

Y	CoPUC, *Verified Petition of Trial Staff of the Commission, CEO, UCA, and Public Service for a Variance from Decision No. C18-0761 and Any Other Requirements, Request for Shortened Notice and Intervention Period, and Request for Approval of Associated Procedures,* filed on November 10, 2025, in Proceeding No. 25V-0480E
Z	CoPUC, Tri-State, *2025 Annual Progress Report*, filed on December 1, 2025, in Proceeding No. 23A-0585E
AA	CoPUC, Decision No. R24-0602, issued on August 22, 2024, in Proceeding No. 23A-0585E
BB	CoPUC, Decision No. C25-0892, issued on December 10, 2020, in Proceeding No. 25V-0480E
CC	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1-Attachment F (*Electric Energy and Demand Forecast*, Public)
DD	CoPUC, Hrg. Ex. 103, Direct Testimony and Attachments of Brian L. Thompson, Rev. 1, filed on May 24, 2024, in Proceeding No. 23A-0585E
EE	PRPA, 2024 Integrated Resource Plan (Apr. 2023)
FF	PRPA, Craig Units 1&2 (Yampa Project) (2026)
GG	PacifiCorp, Utah Integrated Resource Plan Volume I (Mar. 31, 2025)
HH	SPP, *SPP Reliability Plan* (June 2, 2025)
II	NERC, *Emergency Operations*
JJ	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Brad Nebergall, filed on December 1, 2020, in Proceeding No. 20A-0528E, Proceeding 20A-0528E
KK	Division, *Operating Permit No. 96OPMF155* (July 1, 2021)
LL	Division, *Technical Review Document for Operating Permit 96OPMF155* (Jan. 2005)
MM	Tri-State, General APEN- Form APCD-200 (Apr. 21, 2025)
NN	Division, *Colorado Visibility and Regional Haze SIP for the Twelve Mandatory Class I Federal Areas in Colorado* (Dec. 15, 2016)
OO	CoPUC, Hrg. Ex. 101, Direct Testimony and Attachments of Lisa K. Tiffin, Rev. 1, filed on May 15, 2024, in Proceeding No. 23A-0585E, Attachment LKT-1 – Attachment G-1 (Astrape Consulting, *Reserve Margin and Effective Load Carrying Capability (ELCC) Study*, Public (Aug. 2, 2023)
PP	Department, Order No. 202-25-10 (Nov. 25, 2025)
QQ	Tri-State, *U.S. DOE Orders Tri-State to Keep Craig Generating Station Unit Operating for Next 90 Days* (Dec. 31, 2025)
RR	Powell, R., 1 coal plant open amid order (Jan. 6, 2026)
SS	Behr, P., *PJM to ratchet down projected AI power demand for eastern US* (Jan. 6 , 2026)
TT	Department, Order No. 202-26-21 (Mar. 30, 2026)
UU	Tri-State, *Request for Clarification and for Rehearing of Tri-State Generation and Transmission Association and Platte River Power Authority* (Jan. 29, 2026)

VV	CoPUC, Tri-State, Notice of 2026 Resource Adequacy Annual Report, filed on March 17, 2026, in Proceeding No. 26M-0028E
WW	NERC, *Long-Term Reliability Assessment* (Jan. 2026)
XX	Department, Order No. 202-26-16 (Feb. 17, 2026)
YY	Department, Order No. 202-26-17 (Feb. 23, 2026)
ZZ	Department, Order No. 202-26-18 (Mar. 16, 2026)
AAA	Department, Order No. 202-26-19 (Mar. 23, 2026)
BBB	Department, Order No. 202-26-20 (Mar. 23, 2026)
CCC	State of Colorado, The State of Colorado's Request for Rehearing, Motion to Intervene, and Stay Request (Jan. 28, 2026)
DDD	Letter from Jerome H. Sturhahn, Senior Vice President of Tri-State, to Shannon McMillian, Compliance and Enforcement Program Manager, CDPHE (Jan. 26, 2026)
EEE	CoPUC, Tri-State, Notice Regarding Phase II Developments, filed on March 17, 2026, in Proceeding No. 23A-0585E
FFF	SPP, *Current Grid Conditions* (Apr. 7, 2026)
GGG	SPP, *Current Grid Conditions* (Apr. 20, 2026)
HHH	Cook, A., *NERC to OMS: Long-term Assessment not a Predictor of Risk* (Feb. 10, 2026)
III	Brown, C., Plumer, B., *Trump Wants to Halt Almost All Coal Plant Shutdowns. It Could be Messy* (Jan. 16, 2026)
JJJ	Harder, A., *Exclusive: Wind projects pile up as Pentagon reviews stall* (Mar. 30, 2026)
KKK	Department, Order No. 2026-26-31 (June 26, 2026)
LLL	State of Colorado, The State of Colorado's Request for Rehearing, Motion to Intervene, and Stay Request (Apr. 28, 2026)
MMM	Tri-State, *Request for Clarification and for Rehearing of Tri-State Generation and Transmission Association and Platte River Power Authority* (Apr. 29, 2026)
NNN	NERC, 2026 Summer Resource Adequacy (May 2026)
OOO	Department, Order No. 202-26-22 (May 19, 2026)
PPP	Department, Order No. 202-26-24 (May 21, 2026)
QQQ	Department, Order No. 202-26-28 (June 12, 2026)
RRR	Department, Order No. 202-26-29 (June 18, 2026)
SSS	Department, Order No. 202-26-30 (June 18, 2026
TTT	Department, Order No. 202-26-26 (June 4, 2026)
UUU	WECC, Summer 2026 Assessment Overview
VVV	WECC, 2025 Western Assessment Supplemental Information
WWW	Intentionally Left Blank
XXX	Intentionally Left Blank
YYY	Intentionally Left Blank
ZZZ	CoPUC, Tri-State, *Phase II Status Update*, filed on June 30, 2026, in Proceeding No. 23A-0585E

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit YYY: Request for Rehearing of Tri-State Generation and Transmission Association and Platte River Power Authority (July 24, 2026)

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Pursuant to Section 313(a) of the Federal Power Act (FPA),[1] and Rule 713 of the Rules and Regulations of the Federal Energy Regulatory Commission (FERC or Commission),[2] and the applicable rules of practice and procedure,[3] Tri-State Generation and Transmission Association, Inc. (Tri-State) and Platte River Power Authority (Platte River) (together, Petitioners) file this Request for Rehearing of Order No. 202-26-31 dated June 26, 2026 (the Order) requiring Petitioners and their co-owners to keep coal-fired Unit 1 of the Craig Generating Station (Craig Station) in Craig, Colorado (Craig Unit 1) open and available to operate notwithstanding its long-planned retirement. Craig Unit 1 was originally scheduled to shut down by December 31, 2025.[4]

SUMMARY

Section 202(c) provides that "during" an emergency, the U.S. Department of Energy (DOE) is authorized to require extraordinary steps be taken to serve the public interest. 16 U.S.C. § 824a(c)(1). The Order finds that such an emergency exists—but indicates that the claimed energy shortages DOE has identified are not likely to occur, if ever, until ***2034***—more than seven years—or ***thirty*** 90-day Section

[1] 16 U.S.C. § 825l.

[2] 18 C.F.R. § 385.713 (2026).

[3] U.S. Dep't of Energy, DOE Rehearing Procedures, https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (last visited Jan. 15, 2026); *see also* 18 C.F.R. §§ 385.214 (2026), 385.713.

[4] Petitioners are co-owners of Craig Unit 1, and named recipients of the Order. Under the Commission's rules and regulations they are parties to this proceeding. However, if necessary to give them party status, out of an abundance of caution, Petitioners ask that this filing also be treated as a motion to intervene under Rule 214 of the Commission's Rules and Regulations. Petitioners' position on the Order and the nature of their interest are set forth in detail in this filing.

202(c) renewal cycles in the future. That emergency, should it ever come to pass, cannot be solved by requiring that Craig Unit 1, a more than 45-year-old coal plant, continue operating today. It cannot be solved by allowing dispatch of Craig Unit 1 during the period of the current Order. Petitioners raised many of these and other concerns in their request for rehearing and clarification responding to DOE's initial and second Section 202(c) orders targeting Craig Unit 1.[5]

Petitioners again request rehearing to bring to DOE's attention the myriad constitutional, procedural, and evidentiary defects of the Order. Regardless of whether the Order survives such scrutiny, it effects an uncompensated physical and regulatory taking of Petitioners' property interests in Craig Unit 1 and associated water, fuel, and transmission resources. This taking does not come with just compensation, because (1) the processes by which Petitioners could potentially obtain recovery are insufficient and unclear; and (2) these processes fail to provide *compensation* from the taking party—the federal government—rather than facilitating potential compensation from private third parties (including Petitioners).

The Order is also defective on the merits. It fails to articulate a valid emergency, and its chosen remedy—keeping Craig Unit 1 open and available for dispatch—does not respond to the emergency it purports to identify. Because the

[5] *In re Craig Order No. 202-25-14*, Request for Clarification and for Rehearing of Tri-State Generation and Transmission Association and Platte River Power Authority (Jan. 29, 2026), https://www.energy.gov/documents/request-clarification-and-rehearing-tri-state-generation-and-transmission-association-and (the First Rehearing Request); *In re Craig Order No. 202-26-21* Request for Clarification and for Rehearing of Tri-State Generation and Transmission Association and Platte River Power Authority (April 29, 2026), https://www.energy.gov/documents/request-rehearing-tri-state-generation-and-transmission-association-and-platte-river (the Second Rehearing Request).

contemplated "emergency" does not occur until 2034, the Order fails to provide constitutionally adequate due process before deprivation of Petitioners' property interests. Similarly, the Order is procedurally defective; it fails to incorporate statutorily mandated consultation between DOE and other agencies and neglects to consider any alternatives to its proposed plan or the consequences of continuing with the present course of action. Finally, the Order does not align with the statutory objectives of the Federal Power Act (FPA), and DOE never explains how it could.

Petitioners seek to work with all levels of government to provide consumers with reliable and affordable electricity. But Petitioners cannot fulfill this mission when agencies impede years of concerted planning and mandate disruptive and costly changes that do not promote reliability or affordability. This is not what Section 202(c) was intended for. Petitioners urge DOE to reconsider its approach.

STATEMENT OF ISSUES

Pursuant to FPA Section 313(a), Petitioners request clarification and, in the alternative, rehearing based on the following issues:

1. By mandating Craig Unit 1's availability to operate and the terms under which it shall operate, and requiring related changes to Petitioners' physical property, the Order constitutes both a physical and regulatory taking. Because the Order does not provide "just compensation" from the government, this is an uncompensated taking in violation of the Fifth Amendment to the United States Constitution. *United States v. Pewee Coal Co.*, 341 U.S. 114, 116 (1951); *Horne v. Dep't of Agric.*, 576 U.S. 351 (2015); *Ruckelshaus v. Monsanto Co.*, 467 U.S. 986, 1011 (1984).

2. Because DOE failed to establish the existence of an emergency, and, because of the temporal and geographic disconnect between the energy reliability concerns described by the Order and the means DOE directs for addressing those concerns as compared to alternatives, DOE failed to establish that the purported emergency here is addressed by the continued operation and dispatch of Craig Unit 1 or that the Order "best meet[s] the

emergency and serve[s] the public interest." 16 U.S.C. § 824a(c); 10 C.F.R. § 205.373 (2026). It is, therefore, contrary to law and arbitrary and capricious.

3. DOE predicated the Order on long-term concerns, and not an existing emergency, and reissued the Order notwithstanding the due-process objections Petitioners raised in their prior requests for rehearing. Therefore, Petitioners were denied any meaningful opportunity to be heard, notwithstanding time and notice permitting such process. This violates the Due Process Clause of the Fifth Amendment and is contrary to the procedural protections contemplated by the Administrative Procedure Act and the FPA. *Pa. Gas & Water Co. v. FPC*, 427 F.2d 568, 576 (D.C. Cir. 1970); *S. Allegheny Pittsburgh Restaurant Enterprises, LLC v. City of Pittsburgh*, 806 F. App'x 134, 139–41 (3d Cir. 2020).

4. The Order fails to incorporate any statutorily required consultation between DOE and the agency "with expertise in the environmental interest protected by" the laws or regulations waived by a renewed order. 16 U.S.C. § 824a(c)(4)(B). It is, therefore, contrary to law and arbitrary and capricious.

5. The Order does not align with the statutory objectives of the FPA, because it requires the operation and availability for dispatch of an uneconomic resource, and disrupts ordinary and orderly planning, development, and investment in generation resources. It is, therefore, contrary to law and arbitrary and capricious.

BACKGROUND

A. The Petitioners

Tri-State is a wholesale generation and transmission cooperative operating on a not-for-profit basis with its principal place of business in Westminster, Colorado. Organized and existing pursuant to the Colorado Cooperative Act,[6] Tri-State is a public utility subject to FERC jurisdiction under Part II of the FPA.[7] Tri-State is wholly owned by its electric distribution cooperative and public power district

[6] COLO. REV. STAT. § 7-55-101 *et seq.* (2019) (Cooperatives- General); Articles of Incorporation (2020).

[7] Tri-State Generation and Transmission Ass'n, 170 FERC ¶ 61,221, at P 37 (2020).

members (Utility Members) and three non-Utility Members (Non-Utility Members)[8] and was formed by its Utility Members for the purpose of providing the Utility Members with transmission services and wholesale power for resale to their retail customers.

Tri-State has 11 Utility Members with retail customers located in New Mexico and three Utility Members with retail customers in Nebraska,[9] all of which are outside the 2025 Western Electricity Coordinating Council (WECC) Rocky Mountain region that DOE identified as the region experiencing an emergency in the Order. The retail service territories of Tri-State's Utility Members cover approximately 182,000 square miles and their customers include rural residences, farms and ranches, and large and small businesses and industries, serving approximately 522,000 retail electric meters. Tri-State's Utility Members are the sole state-certificated providers of electric service to retail (residential and business) customers within their designated service territories.

Tri-State owns, directly or indirectly, or controls the output of, various power generation facilities, and purchases wholesale power within both the Western and Eastern Interconnections. Among other generation facilities, Tri-State is a partial owner of Craig Unit 1, with a 24% ownership share. Tri-State's generating facilities

[8] Tri-State's Non-Utility Members are: (i) MIECO, Inc., a wholesale supplier of natural gas in the United States; (ii) Olson's Greenhouses of Colorado, LLC, a grower/distributor of plants throughout the western United States that has a contract to purchase thermal energy from Tri-State; and (iii) Ellgen Ranch Company, which leases property from a Tri-State subsidiary.

[9] Tri-State has six Utility Members that maintain headquarters in Nebraska, three of which operate outside the emergency assessment area.

are included in the Western Power Pool reserve sharing program. This program facilitates sharing of generation reserves to be activated during a system emergency, such as loss of a generating unit or transmission line. Tri-State began participating in the Southwest Power Pool's (SPP) expanded regional transmission organization (RTO) in the Western Interconnection in April 2026.[10]

Platte River is a not-for-profit, municipally-owned power utility and joint action agency that generates reliable, financially sustainable, and environmentally responsible electricity for its owner communities of Estes Park, Fort Collins, Longmont, and Loveland, Colorado. Platte River is a political subdivision of the State of Colorado and a government-owned utility under FPA Section 201(f), 16 U.S.C. § 824(f). Headquartered in Fort Collins, Colorado, Platte River furnishes cost-of-service wholesale electrical power and energy to its four owner communities.

Platte River is a partial owner of Craig Units 1 and 2, with an 18% ownership share in the Craig units. Platte River's share of the total net capacity from both Craig units is 151 MW. Platte River also owns and operates an integrated transmission system of high-voltage aerial and underground power lines that deliver electricity to the electric utilities of Platte River's owner communities in Northern Colorado. Like Tri-State, Platte River began participating in SPP's expanded RTO in April 2026.

[10] As used herein, SPP refers to the SPP RTO's western expansion. It does not include SPP Markets+.

B. The Craig Generating Station

Craig Generating Station is a three-unit, coal-fired power plant located in Craig, Colorado. Craig Units 1 and 2 were built and are jointly owned by several utilities through what is known as the Yampa Project. Tri-State operates those two units on behalf of all the co-owners, including Platte River, PacifiCorp, Public Service Company of Colorado, and the Salt River Project Agricultural Improvement and Power District. Tri-State separately owns and operates Craig Unit 3. In April 2026, the owners of Craig Units 2 and 3 became market participants in SPP—the culmination of a multi-year planning process—and began to bid those units into SPP's market. Craig Unit 1 is currently participating as a resource in SPP solely because of the Order.

As a result of changed market conditions and regulatory requirements, the retirement of the Craig units has been planned, reviewed, and integrated into state-approved resource portfolios, and the owners have planned for their closure for nearly a decade—beginning with Craig Unit 1 by December 31, 2025, followed by Craig Unit 3 by January 1, 2028, and Craig Unit 2 by September 30, 2028. Colorado Air Quality Control Commission Regulation No. 23 on Regional Haze Limits now specifies a retirement date for each Craig unit.[11] Unit 1's retirement date was adopted in 2016, in a revision of what was then Colorado Air Quality Control Commission Regulation No. 3, which was approved by the Environmental Protection Agency

[11] COLO. CODE REGS. 1001-27.

(EPA) in 2018.[12] Retirement dates for Craig units were later codified into Regulation No. 23.

The Craig units have been fueled primarily by coal from the nearby Colowyo and Trapper mines. The Colowyo Mine has ceased active mining and transitioned to full reclamation, with two pits in final reclamation and the third transitioned to reclamation on October 15, 2025. Similarly, the Trapper Mine is scheduled to cease active mining and convert to site remediation in calendar year 2026. Before the closure of the Colowyo Mine, Tri-State stockpiled sufficient coal to meet Tri-State's projected demand for Craig Units 2 and 3 through their respective planned retirement dates. Before the Trapper Mine closes, Platte River will have stockpiled sufficient coal to meet its projected demand for Craig Unit 2 through its planned retirement date.

As part of its multi-year resource plan, which incorporated the long-planned retirement of Craig Unit 1, Tri-State has placed into service the 145-MW Axial Basin generating facility. This facility, approximately 26 miles from the Craig facility, relies on much of the same transmission infrastructure. Absent the retirement of Craig Unit 1, the interconnection of the Axial Basin facility faces transmission constraints such that, when Craig Unit 1 remains interconnected and available to operate,

[12] *See* Approval and Promulgation of Implementation Plans; Colorado; Regional Haze 5-Year Progress Report State Implementation Plan, 84 Fed. Reg. 47884 (Sept. 11, 2019); Co. Air Pollution Control Div., Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado (Dec. 15, 2016), https://oitco.hylandcloud.com/POP/DocPop/DocPop.aspx?docid=3303135.

Tri-State may be required to curtail output from Axial Basin (particularly when all facilities are generating at or near full output) due to limited transmission capacity.

Continued operation of Craig 1 during severe drought conditions also imposes unplanned demands on scarce water supplies and will reduce the resilience of Craig Units 2 and 3 in future years. Craig Station, including Unit 1, is supplied by water from the Yampa River. The Yampa River is experiencing severe drought conditions, with portions of the upper basin elevated to "Exceptional Drought" by the U.S. Drought Monitor, its most extreme drought class, late this spring.[13] The reduced flows in the Yampa River present significant challenges to water managers, reducing physical and legal water availability, requiring the release of more water from storage, and reducing the certainty that reservoirs can be refilled following releases, threatening water security in future years if drought continues.

Craig Station relies on direct flow water rights that are relatively junior in priority; these direct flow rights are subject to administrative water rights "calls" from senior irrigation water rights downstream. These diversions are also subject to physical availability constraints—intake pumps need adequate streamflows passing Craig Station's raw water for intake.

Currently, the additional water needed for Craig Unit 1 is supported by voluntary partial forbearance by downstream senior irrigation water rights and

[13] *See Drought Conditions for Moffat County, CO*, National Integrated Drought Information System (last visited Jul. 24, 2026), https://www.drought.gov/states/colorado/county/moffat; *Drought Conditions for Routt County, CO*, National Integrated Drought Information System (last visited Jul. 24, 2026), https://www.drought.gov/states/colorado/county/routt.

voluntary releases from upstream reservoirs. There is no guarantee that these voluntary practices will continue, and in fact, these practices may not be sustainable for the duration of the irrigation season.

In the immediate term, water needs for Craig Station may be met through releases from storage. Partly in anticipation of Craig Unit 1's closure, the owners of Craig Station prudently decided not to renew a storage contract for water from Stagecoach Reservoir, and to rely instead exclusively on their water storage rights in Elkhead Reservoir.[14] A mandate to operate Craig Unit 1, without this backup leased reservoir supply, places additional stress on the remaining storage supplies. This stress, exacerbated by higher-than-anticipated water demand and worse-than-anticipated drought, is increasingly likely to become a critical problem.

Further, for every incremental water release from Elkhead Reservoir, an equal amount must be stored before the following water year to restore water security to Craig Station, and there is no guarantee of that storage if the drought persists. A mandate to operate Craig Unit 1 leaves Tri-State's ability to refill its storage at Craig Station in doubt, reducing water security and imperiling the ability to operate any, or even all, of the Craig Units in the future.

[14] The Colorado River District recently began releasing water from Elkhead Reservoir to mitigate the impacts of extreme drought and critically low streamflows in the Yampa River Valley. See Strategic Reservoir Releases Begin to Protect Yampa River Water Users and River Flows, Colorado River District (Jul. 16, 2026) https://www.coloradoriverdistrict.org/press-release-strategic-reservoir-releases-begin-to-protect-yampa-river-water-users-and-river-flows/.

C. Craig Unit 1

Craig Unit 1 can produce up to 427 MW of electricity and has been running since 1980. Over the last ten years, the operations and maintenance cost (without consideration of coal cost or depreciation expense) to run Craig Unit 1 has totaled in the millions of dollars annually. By the standards of an older coal plant, Craig Unit 1 has generally provided reliable performance when called upon. However, in the last three years (due primarily to economic factors and some forced outages), Craig Unit 1 has run at well below half of its maximum output without compromising Petitioners' ability to meet their total generation demands reliably.

Operation and maintenance of Craig Unit 1 have been undertaken prudently to reflect the scheduled 2025 retirement. Since 2019, the Craig Unit 1 owners scheduled and performed only that maintenance appropriate for a unit that planned to cease operation at the close of 2025. On December 19, 2025, the unit suffered a valve failure that rendered Craig Unit 1 inoperable, although the unit is now available to operate following repairs.[15]

D. DOE Order No. 202-25-14

On December 30, 2025, DOE issued Order No. 202-25-14, declaring that "an emergency exists within the [WECC-NW] assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes." DOE Order No. 202-25-14 at 1 (Dec. 30, 2025). Petitioners sought rehearing

[15] Tri-State Generation & Transmission Ass'n, Inc., *U.S. DOE Orders Tri-State to Keep Craig Generating Station Unit Operating Next 90 Days*, TRI-STATE (Dec. 31, 2025), https://tristate.coop/us-doe-orders-tri-state-keep-craig-generating-station-unit-operating-next-90-days.

and clarification of Order No. 202-25-14, raising multiple legal issues, including DOE's denial of Petitioners' constitutionally protected due process rights, the lack of an appropriate mechanism for just compensation, and DOE's failure to consider alternatives for what the order itself recognized was not an immediate, time-sensitive emergency. DOE denied the First Rehearing Request by operation of law pursuant to 16 U.S.C. § 825l(a) by failing to substantively respond to the request within 30 days, and issued a notice to this effect on March 2, 2026. On June 24, 2026, DOE issued Order No. 202-25-14B, which modified the discussion in Order No. 202-25-14 but reached the same result.

This initial order expired on March 30, 2026.

E. DOE Order No. 202-26-21

On March 30, 2026, DOE issued Order No. 202-26-21, continuing Order 202-25-14. The Order declared that "an emergency exists within the Western Electricity Coordinating Council (WECC) Rocky Mountain assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes." DOE Order No. 202-26-21 at 1 (Mar. 30, 2026). The Order further declared that "[t]he availability of electricity from Craig Unit 1 will continue to be critical to maintain reliability in the WECC Rocky Mountain assessment area." *Id.* at 3. Its emergency was predicated on (1) "increasing demand" and (2) "shortage from accelerated retirement of generation facilities [that] will continue in the near term and are also likely to continue in subsequent years." *Id.* at 6. DOE stated, "[t]his could lead to the loss of power to homes, and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety." *Id.*

DOE predicated its energy reliability concerns on the 2025 Long-Term Reliability Assessment (2025 LTRA) from the North American Electric Reliability Corporation (NERC) for the WECC-Rocky Mountain assessment area, which does not anticipate any shortfalls in supply before Summer 2034. *Id.* at 3. DOE also pointed to the 2025 WECC Western Assessment of Resource Adequacy. The concerns included (1) projected regional load growth; (2) planned retirement of generation facilities fueled by coal and natural gas; and (3) the "prolific growth of data centers" constituting a "new and unexpected source of load growth." *Id.* at 3–5.[16]

This second order expired on June 28, 2026.

F. DOE Order No. 202-26-31

On June 26, 2026, DOE issued Order No. 202-26-31, continuing Orders 202-25-14 and 202-26-21. The Order is similar to Order No. 202-26-21, although not identical.[17] In its discussion of the claimed "Continuing Emergency Conditions," the

[16] Order No. 202-26-21 placed these concerns in the broader context of Executive Orders 14156 and 14262. Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency; Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[17] The Order contains a substantial number of small adjustments in the terminology it uses to describe both the DOE's determinations and Petitioners' obligations. For example, Order No. 202-26-21 states on page 2 that the Secretary "determined that the continued **availability** of Craig Unit 1 would provide additional generation capacity, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety." The current Order, however, states that the Secretary "determined that the continued **operation** of Craig Unit 1" would have the same impacts. Similarly, in the "Order" section of these documents, where the first and second iterations of these orders described a "shortage from **accelerated** retirement" of generation, the most recent order describes a "shortage from **premature** retirement" of generation. Petitioners do not understand these and similar unexplained variances to be material. To the extent changes of

Order includes a discussion of NERC's 2026 Summer Reliability Assessment.[18] The Order acknowledges that NERC's evaluation is that, within the WECC-Rocky Mountain region, reserve margins are expected to remain above reference levels for summer 2026.[19] The Order also makes reference to an April 20 memorandum issued by President Trump.[20] The Order requires Petitioners and the other co-owners of Craig Unit 1 to:

1. From June 29, 2026, take all measures necessary to ensure that Craig Unit 1 is available to operate, with SPP directed to take every step to employ economic dispatch of Craig Unit 1 to minimize costs to ratepayers, with Tri-State and the co-owners directed to comply with all orders from SPP related to the availability and dispatch of Craig Unit 1.
2. Limit operation of Craig Unit 1 to the times and within the parameters established *supra* in order to minimize adverse environmental impacts, and to provide a daily notification to the Department reporting whether Craig Unit 1 has operated in compliance with the Order.
3. Comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. The Order specifies that it does not provide relief from "any obligation to pay fees, or purchase offsets or allowances for emissions that occur during the emergency conditions, or to use other geographic or temporal flexibilities available to generators."[21]
4. By July 14, 2026, provide DOE with information concerning the measures each has taken and is planning to take to ensure the operational availability of Craig Unit 1 consistent with the Order, as well as additional information regarding the environmental and

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this and similar kinds are meant to convey a materially different meaning in this Order as compared to earlier, substantially similar ones, this intent is unclear from the Order itself, and that absence of clarity renders the Order arbitrary and capricious.

[18] *See* Order at 4.

[19] *Id.*

[20] *Id.* at 5–6.

[21] *Id.* at 7.

operational impacts of the Order and its compliance with the conditions of the Order, in each case as requested by DOE.

5. File tariff revisions or waivers with FERC to effectuate the Order, as needed.

The Order is effective from June 29 through September 26, 2026. Tri-State has submitted and continues to submit daily notifications to DOE as the Order requires.

ARGUMENT

Petitioners seek rehearing on two fronts. *First*, the Order effectuates a taking of Petitioners' property under the Fifth Amendment to the United States Constitution without an adequate process to obtain constitutionally required compensation. *Second*, the Order does not meet either the Constitution's or Section 202(c)'s requirements for a reasoned, procedurally adequate finding of a valid emergency that compels operation of Craig Unit 1.

I. THE ORDER CONSTITUTES AN UNCOMPENSATED TAKING OF PETITIONERS' PROPERTY INTERESTS

Petitioners chose to close Craig Unit 1 to meet reliability targets and achieve regulatory goals, and have taken numerous steps over the years to prepare for its closure. The Order nevertheless requires Tri-State to operate the facility beyond that planned retirement date, effecting an uncompensated taking of Petitioners' property in violation of the Fifth Amendment of the United States Constitution. By compelling continued operational availability of Craig Unit 1, DOE took effective control over the facility itself and mandated changes to Petitioners' infrastructure and business operations, constituting both a *per se* physical and regulatory taking.

The Order's taking comes with no constitutionally adequate avenue for just compensation. FERC cost recovery shifts compensation onto ratepayers; it does not

assure compensation *from the government*. And, due in part to the broad scope of the declared energy emergency, FERC cost recovery related to the Order will be procedurally and substantively novel and could leave material costs unrecovered from the Order's putative beneficiaries.

A. The Order Constitutes a Physical Taking

The Fifth Amendment provides, "private property [shall not] be taken for public use, without just compensation." U.S. Const. amend. V. "When the government physically acquires private property for a public use, the Takings Clause imposes a clear and categorical obligation to provide the owner with just compensation." *Cedar Point Nursery v. Hassid*, 594 U.S. 139, 147 (2021) (citation omitted).

Physical takings can take various forms, including intermittent or limited-value intrusions. *Id.* at 149–55; *see also Loretto v. Teleprompter Manhattan CATV Corp.*, 458 U.S. 419 (1982). Moreover, "[i]f government action would qualify as a taking when permanently continued, temporary actions of the same character may also qualify as a taking." *Ark. Game & Fish Comm'n v. United States*, 568 U.S. 23, 26 (2012). This is true even when the government has not seized title to property but rather directed it to operate in a particular way. Temporary seizures of property to operate are takings "in as complete a sense as if the [g]overnment held full title and ownership." *See Pewee Coal Co.*, 341 U.S. at 116 (quoting *United States v. United Mine Workers of Am.*, 330 U.S. 258, 285–86 (1947)). A physical taking can occur even without the literal physical occupation of physical assets by the government: instead, a physical taking occurs when the government assumes "ultimate control" of physical

property, even if existing management ends up responsible for "conduct[ing] operations" on the government's behalf. *See Pewee Coal Co.*, 341 U.S. at 116.

The Order operates as a physical taking in two interrelated ways. *First*, by directing Petitioners to maintain and operate Craig Unit 1, on a prolonged basis, and in clear departure from Petitioners' own planned retirement of the facility, the Order falls within a near-century-old tradition of classifying mandatory operations—even under wartime and emergency authorities—as takings requiring compensation. *Second*, the Order constitutes a physical taking by compelling Petitioners to make material physical changes to the plant, such as repairing out-of-service equipment like feedwater heater tubes, ash blowers, and side stream filter pumps; requiring additional staff onsite; and physically diverting water and coal allocated for Craig Units 2 and/or 3 to fuel Craig Unit 1. Reduction of these stockpiled reserves requires Petitioners to rely on finite, stored reserves of water earmarked for Units 2 and 3, or acquire it from uncertain sources and at uncertain future prices (if it can be acquired at all), creating an additional uncompensated cost. It similarly requires Petitioners to obtain replacement coal that will be compatible for use in Units 2 and 3, from uncertain sources and at uncertain future prices, creating an additional uncompensated cost. And because of physical transmission constraints, Craig Unit 1's operations could limit the circumstances where SPP can dispatch the nearby Axial Basin generating facility.

1. The Order's Direction of Prolonged Operations at Craig Unit 1 Contrary to Petitioners' Plan to Retire the Facility Constitutes a Physical Taking

Section 202(c) was enacted to address energy shortages that occurred during the First World War,[22] making it particularly suitable for analysis under post-war interpretations of the Takings Clause. These cases show that, even in the context of an emergency, where the government takes control of part or all of a business's facilities to use and operate for the government's purposes, a compensable taking occurs, *see*, *e.g.*, *United States v. Gen. Motors Corp.*, 323 U.S. 373 (1945) (government seizure of part of leased warehouse space for military purposes was a compensable taking). Similarly, where the government requires a private business to operate in the public interest, this too constitutes a *per se* physical taking. *Pewee Coal Co.*, 341 U.S. at 116 (taking occurred when government responded to work stoppages and strikes at coal mines by directly operating them or arranging for their continued operation). This includes a scenario where non-government actors, such as existing management and ownership, are delegated responsibility for effecting the government's orders: the key question is whether the government took and "retained ultimate control" over operations. *United Mine Workers of Am.*, 330 U.S. at 288. These cases illustrate that a taking is particularly likely to occur where the imposition of government control extends over a lengthy period of time. *See Gen. Motors Corp.*, 323 U.S. at 375 (warehouse seized for more than a year); *Pewee Coal*

[22] Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789, 789–846, 800–02 (2024) ("Rolsma (2024)").

Co., 341 U.S. at 115 (government-directed operation of coal mine continued for more than 160 days).[23] Ultimately, the core question is "whether the government has physically taken property for itself or someone else—by whatever means—or has instead restricted a property owner's ability to use his own property." *Cedar Point Nursery*, 594 U.S. at 149.

In that light, the Order constitutes a taking of Petitioners' property. The Order requires Petitioners to, in relevant part: (1) take all measures necessary to ensure that Craig Unit 1 is available to operate; (2) limit operation of Craig Unit 1 to certain times and parameters; and (3) make Craig Unit 1 available for dispatch at the direction of SPP, a non-governmental actor. Although Petitioners' existing personnel are responsible for carrying out these requirements, the DOE retains and is exercising ultimate control over events at Craig Unit 1. Compliance with these requirements has compelled Petitioners to take significant steps they would not otherwise take for a prolonged period of time. DOE's renewed Order extends the period of compelled availability to roughly nine months, and nothing in the Order suggests this control will be temporary rather than renewed through successive emergency declarations. This closely resembles the mandate to operate that the

[23] Indeed, the federal government recently recognized that where the government appropriates the right to control operation of a facility and deprives owners of their freedom to dispose of their property, a taking has occurred. *See* EPA-R08-OAR-2024-0607-0067, Regional Haze Round 2 at 19–21 (Jan 9, 2026), https://www.regulations.gov/document/EPA-R08-OAR-2024-0607-0067 (describing how the "unconsented closure" of a coal-fired power station constituted a per se taking of the facility owner's property) (citing *Cedar Point Nursery v. Hassid*, 594 U.S. 139 (2021) and *Horne v. Dep't of Agric.*, 576 U.S. 351 (2015)).

Pewee Coal Court held was a taking.[24] By requiring Petitioners to involuntarily keep Craig Unit 1 available for operations according to SPP's instructions—for not hours or days but months—DOE enacts a taking.

2. The Order Mandates Physical Changes to Petitioners' Property That Constitute a Physical Taking

The physical changes to Petitioners' property mandated by the Order also constitute a *per se* physical taking of Petitioners' property rights in Craig Unit 1 and other related property, such as water and fuel. *First*, continued operation of Unit 1 requires water and fuel, which compels Petitioners to use the Craig facility's limited water and fuel reserves intended exclusively for Craig Units 2 and/or 3; these reserves were acquired and measured for the anticipated operation of two specific coal units and based on the assumption that Craig Unit 1 would retire at the end of 2025. Because the Order forces Petitioners to surrender water and coal inventory for the government's chosen public purpose—water and coal that Petitioners acquired, allocated, and reserved for other units—it effects a *per se* physical taking of that property. *Second*, transmission capacity limitations for Petitioners' facilities at and near Craig Unit 1—the other Craig units and Axial Basin—mean that requiring Craig Unit 1 to remain interconnected and possibly operating constrain the ability of these resources to fully access the grid. And *third*, mandating that Petitioners make

[24] The *Pewee Coal* Court did not enjoin the government's actions—the wartime emergency justified the government's effort to keep coal mines operational in 1943, the heat of the war. The fact of a justified emergency, however, did nothing to abate the Takings Clause requirement that the government compensate the plaintiff. *See Pewee Coal Co.*, 341 U.S. at 118 (holding that government is "entitled to the benefits and subject to the liabilities" of operating a facility it takes over).

Craig Unit 1 ready for operations has compelled Petitioners to make material physical changes to Craig Unit 1, including repairing out-of-service equipment that would otherwise remain unused.

a. The Craig Facility's Water Reserve

All three Craig Units were designed to run on water obtained from the Yampa River, backstopped by the Elkhead Reservoir and, before Craig Unit 1's expected retirement, the Stagecoach Reservoir, which is unavailable for Craig Station's use as of July 14, 2020. Before giving up rights in the Stagecoach Reservoir, Tri-State determined that the Elkhead reserves were sufficient to operate Craig Units 2 and 3 until their respective retirements. The only readily available source of water for Craig Unit 1 to maintain readiness, and use for dispatch, is the water acquired and allocated for Craig Units 2 and 3.[25] These water reserves have been depleted by the combination of recent hot, dry weather exceeding historically normal conditions and by the additional demands placed on Craig Station by the Order.

This too constitutes a taking. *See Horne v. Dep't of Agric.*, 576 U.S. 351, 357–65 (2015) (USDA requirement that a percentage of a grower's crop be set aside for public use constituted a *per se* physical taking); *Casitas Mun. Water Dist. v. United States*, 543 F.3d 1276, 1288–97 (Fed. Cir. 2008) (where the government required

[25] Diverting this water will require Petitioners to purchase replacement water at uncertain cost, imposing an additional, uncompensated expenditure that independently constitutes a taking. Meanwhile, using more water than anticipated in a drought year could further harm water security for Tri-State, agricultural interests and Colorado communities in future years. In a worst-case scenario, water may simply be unavailable, rendering one or more units of Craig Station inoperable under any conditions and disrupting the reliable generation capacity that Craig Units 2 and 3 currently provide.

construction of a fish ladder and compelled water subject to plaintiff's water rights to be rerouted to the fish ladder, a physical taking had taken place). Just as the government effected a *per se* taking by requiring raisin growers to surrender a specific, identifiable portion of their crop for public use as in *Horne*, or by taking the right to waterflow for public infrastructure as in *Casitas*, by mandating that Petitioners consume water reserves purchased and reserved for Craig Units 2 and/or 3, DOE appropriates that property for a public objective.

Under *Horne*'s reasoning, forced depletion of a utility's water reserves—no less than forced surrender of raisins—constitutes a physical taking of personal property requiring just compensation. This remains the case even if no government actor ever takes title to or assumes possession of the depleted water reserves: a physical taking can occur without the government "taking actual possession" of the property. *Hawaii Hous. Auth. v. Midkiff*, 467 U.S. 229, 244 (1984). It is the "taking's purpose, and not its mechanics," that creates the need to provide just compensation. *Id.*

b. The Craig Facility's Fuel Reserve

All three Craig Units were designed to run on coal obtained from the now-shuttered Colowyo Mine and the soon-to-be-shuttered Trapper Mine.[26] Before closing the Colowyo Mine, Tri-State stockpiled reserves sufficient to operate its share of the Craig Units until their respective retirements. The only readily available source of fuel for Craig Unit 1 to maintain readiness, and to make use of in the event of a

[26] Tri-State believes that co-owners supply their share of Craig Units 1 and 2 through Trapper or other mines.

dispatch, is the reserves acquired and allocated for Craig Units 2 and 3. Just as with the Craig Station's water reserves, depletion of the coal reserves constitutes a taking. Under the same reasoning, forced depletion of a utility's fuel reserves constitutes a physical taking of personal property requiring just compensation, regardless of whether the government ever takes title to the coal reserves burned.[27]

c. Axial Basin

By requiring Tri-State to transmit electricity to the SPP-controlled grid, the Order constitutes appropriation of Tri-State's transmission infrastructure (including transmission infrastructure allocated to Axial Basin), a clear physical intrusion. Even such intermittent intrusion on Petitioners' transmission capacity constitutes a taking. *See Cedar Point Nursery*, 594 U.S. at 153–54 (citing *United States v. Causby*, 328 U.S. 256, 259 (1946)) ("*Causby* held that overflights of private property effected a taking, even though they occurred on only 4% of takeoffs and 7% of landings at the nearby airport.").

Further, the 145-MW Axial Basin generating facility, located near the Craig Generating Station, relies on much of the same transmission infrastructure as the Craig facility. There is insufficient transmission capacity to move electricity generated by all three Craig units and Axial Basin to the broader power grid at the

[27] As with diversion of water resources, diverting this coal will require Petitioners to purchase replacement fuel at uncertain cost, imposing an additional, uncompensated expenditure that independently constitutes a taking. Use of an alternative source of supply not only results in additional costs, but also requires Petitioners to negotiate new contracts and alter operations at the Craig facility to account for variances between the physical qualities of different coal supplies. Meanwhile, using coal with different physical qualities could also require expensive and time-consuming modification of one or more Craig Units to allow such coal to be burned.

same time. This transmission limitation may trigger additional physical intrusion, as ensuring sufficient transmission capacity for Craig Unit 1's compliance with the Order may require curtailment of one or more other generation facilities (especially when the transmission system is operating near capacity).

d. Physical Changes to Craig Unit 1

Ongoing operations at Craig Unit 1 will require continual maintenance and staffing readiness, with further equipment failures requiring repair and staffing (including overtime). Compelling a property owner to make improvements to their property constitutes a physical taking when the mandated improvement benefits others—particularly the public at large—but does not benefit the property owner. "Put in general terms, government may not force a landowner to make an improvement that, while valuable to others, is useless to him" without it constituting a compensable taking. *Furey v. City of Sacramento*, 780 F.2d 1448, 1454 (9th Cir. 1986) (discussing *Norwood v. Baker*, 172 U.S. 269 (1898) and *Myles Salt Co. v. Bd. of Comm'rs*, 239 U.S. 478 (1916)), *abrogated on other grounds, Cumbre Inc. v. State Compensation Ins. Fund*, 403 F. App'x 272 (9th Cir. 2010). The Order requires Petitioners to continue to maintain and operate Craig Unit 1, and to replace equipment and material, even though they had planned to imminently retire the unit for good and Unit 1 is not needed to serve the reliability needs of their respective systems. This is the kind of physical taking described in *Furey*.[28]

[28] This is also a fundamentally different issue than that presented by *Union Bridge Co. v. United States*, 204 U.S. 364 (1907). *Union Bridge* involved a property owner who was compelled to take steps to modify a structure that had been determined to obstruct

B. The Order Constitutes a Regulatory Taking

In addition to being a *per se* physical taking, the Order constitutes a regulatory taking. Regulatory takings occur where the government "imposes regulations that restrict an owner's ability to use his own property" but goes too far. *Cedar Point Nursery*, 594 U.S. at 148. The property rights implicated by the Takings Clause can include contract rights, *see Lynch v. United States*, 292 U.S. 571, 579 (1934), and government-created entitlements with economic value, *Ruckelshaus*, 467 U.S. at 1001–04 (trade secrets constituted property for takings purposes). When evaluating whether a regulatory burden constitutes a taking, courts look to the test established in *Penn Cent. Transp. Co. v. N.Y.C.*, 438 U.S. 104, 124 (1978), which evaluates regulatory takings based on: (1) the regulation's economic impact; (2) its interference with reasonable investment-backed expectations; and (3) the character of the government action. The Order constitutes a regulatory taking under this analysis.

1. Economic Impact

By requiring Petitioners to "take all measures necessary to ensure that Craig Unit 1 is available to operate," the Order places a heavy economic burden on Petitioners. Petitioners incur various operations and maintenance costs to ensure Craig Unit 1 is ready and able to operate at SPP's direction. Moreover, because of limited capacity over common transmission facilities, dispatching Craig Unit 1 while

navigation, *i.e.*, requiring a property owner to themselves stop causing a public nuisance or harm. *Id.* at 400–01. Petitioners are not being required to cease engaging in harmful conduct: they are being required to continue operating, maintaining, and fueling a facility. *Union Bridge Co.*, which predates modern takings jurisprudence, has no bearing on the scenario presented here.

the other Craig Units are operating can impede SPP's ability to dispatch the nearby Axial Basin generating facility. This, in turn, prevents Petitioners from gaining the benefit of a margin on more economic resources, including renewable energy credits (which themselves have tangible economic value).

2. Investment-Backed Expectations

"[T]he regulatory regime in place at the time the claimant acquires the property at issue helps to shape the reasonableness of [investment-backed] expectations." *Palazzolo v. Rhode Island*, 533 U.S. 606, 633 (2001) (O'Connor, J., concurring). Where a change in regulation dramatically disrupts the economic basis for a property owner's choices, it constitutes unreasonable interference with reasonable investment-backed expectations. *See Petworth Holdings, LLC v. Bowser*, 308 F. Supp. 3d 347, 356–58 (D.C. Cir. 2018). An explicit government guarantee forms the basis of a reasonable investment-backed expectation. *See Ruckelshaus*, 467 U.S. at 1011.

The Order disrupts Petitioners' reasonable investment-backed expectations on several fronts. DOE's use of Section 202(c) authority to address potential long-term shortages or grid reliability problems is a substantial and novel change to prior uses of Section 202(c) emergency authority.[29] The Order fundamentally alters DOE's longstanding approach in a novel, untested way that could not be predicted from DOE's previous actions, and certainly not when Petitioners decided a decade ago to

[29] *Rolsma* (2024) at 802–09, 839–46 (discussing paucity of involuntary Section 202(c) orders since World War Two).

retire Craig Unit 1 in 2025. Petitioners could not have fairly anticipated DOE's novel approach to Section 202(c) when it engaged in business planning and made investment decisions; thus, the Order upsets Petitioners' reasonable expectations.[30] Diverting water and coal to Craig Unit 1 to comply with the Order, moreover, depletes Craig Unit 2 and 3's water and fuel reserves and hinders Petitioners' right and ability to freely use those facilities consistent with their investment-backed expectations.[31]

Finally, the electrical generation and transmission industry operates on a long time horizon. Craig Unit 1's planned closure was announced a decade ago, and numerous steps to execute that plan, such as deferring maintenance, reducing staffing, right-sizing water and coal reserves, and redirecting capital expenditures, have been undertaken since. Disruption of these long-term plans upsets Petitioners' reasonable investment-backed expectations. The seizure of a facility eight years in advance of a potential emergency upsets a reasonable expectation that long-term

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[30] These considerations help explain why *AT&T Corp. v. City of Toledo*, 351 F. Supp. 2d 744 (N.D. Ohio 2005) is inapposite. *AT&T Corp.* concerned a utility's ongoing use of an easement granted by a municipality, and the ongoing exercise of typical regulatory oversight of those operations. *Id.* at 747–49. Petitioners, like all entities operating in the energy markets, are routinely asked to comply with typical regulatory burdens like those at issue in *AT&T Corp.* A case involving the ordinary and expected regulation of utility operations does not in any way address the issue presented here: whether the government can compel an owner to continue operating a facility it has decided to retire after years of planning and regulatory approval.

[31] The Order also upsets Petitioners' delicate contractual relationships. Even if Section 202(c) provides protection from enforcement action by Colorado under "environmental" laws, disruption to these longstanding relationships disturbs Petitioners' ability to manage risk, engage in long-term planning, and maintain their reputations as reliable counterparties. Petitioners have made commitments to stakeholders and planned their businesses around complying with existing environmental laws, which form part of their reasonable investment-backed expectations.

resource planning will be the mechanism by which utilities address resource adequacy needs.

3. Character of the Taking

The character of a governmental action is defined by "the purpose and importance of the public interest underlying [the] regulatory imposition, by obligating the court to inquire into the degree of harm created by the claimant's prohibited activity, its social value and location, and the ease with which any harm stemming from it could be prevented." *Maritrans, Inc. v. United States*, 342 F.3d 1344, 1356 (Fed. Cir. 2003) (internal quotation and citation omitted). "A 'taking' may more readily be found when the interference with property can be characterized as a physical invasion by government . . . than when interference arises from some public program adjusting the benefits and burdens of economic life to promote the common good." *Penn Cent.*, 438 U.S. at 124 (citations omitted).

The character of the Order's action further aligns with a regulatory taking. As discussed above in Section (I)(A), the Order effectively commandeers Craig Unit 1, its fuel, the potential dispatch of the nearby Axial Basin facility, and related infrastructure owned by Petitioners. It places Craig Unit 1 under the control of SPP, a non-governmental actor, and requires Petitioners to comply with "all orders" that SPP issues "related to the availability and dispatch of Craig Unit 1." Order at 7. The Order does not merely adjust the benefits and burdens of economic life, but rather directs operational control for a public reliability aim that could—and should—be solved through other means, and by other electrical utilities.

C. Just Compensation

The Takings Clause provides that "private property [shall not] be taken for public use, without just compensation." U.S. Const. amend. V. Whether compensation is "just" is measured by relation "both to an owner whose property is taken and to the public that must pay the bill[.]" *United States v. Commodities Trading Corp.*, 339 U.S. 121, 123 (1950). "The owner's loss is measured by the extent to which governmental action has deprived him of an interest in property." *Wheeler v. City of Pleasant Grove*, 833 F.2d 267, 270 (11th Cir. 1987). Petitioners cannot obtain constitutionally sufficient compensation for the costs the Order imposes for several reasons.

First, SPP's existing market structures do not assure Petitioners they can recover both their variable and fixed costs of continued operation of Craig Unit 1. Under SPP's existing market structure, generators like Petitioners participate by bidding their output into SPP's real-time and day-ahead energy and ancillary services market. SPP's markets assure generators recovery of only their marginal, variable costs—not fixed costs.[32] As a long lead-time reliability resource, Craig Unit 1 is offered for selection within a multi-day resource assessment. If SPP selects the resource for reliability purposes, the resource is compensated for energy costs. SPP does not operate a mandatory all-resource capacity market, a mechanism by which

[32] *See* Market Protocols—SPP Integrated Marketplace, at 39 ("SPP committed Resources are assured recovery of their Start-Up Offer, No-Load Offer and actual incremental Energy costs as defined in the Energy Offer Curve subject to certain eligibility criteria[.]").

generators recover their non-variable (fixed) costs.[33] And, in any event, the Order instructs that Craig Unit 1 "shall not be considered a capacity resource[,]" Order at 7.

Second, while Section 202(c) and its implementing regulations suggest recovery may be possible through FERC rate-making processes, that suggestion is not a promise of constitutional recovery.[34] The scope of the purported emergency, covering the entire WECC–Rocky Mountain region, is broader than just SPP's market. Public Service Company of Colorado's (PSCo) Balancing Authority Area, for example, falls within the WECC–Rocky Mountain region identified as experiencing the "emergency" and thus PSCo presumably benefits from Craig Unit 1's continued operations, but PSCo does not participate in SPP, the mechanism for potential compensation identified in the Order. DOE sets forth no mechanism for navigating these complexities, much less an assurance of just recovery notwithstanding these issues; at minimum DOE should clarify the entities from which it intends to provide

[33] *See* Federal Energy Regulatory Commission, Office of Energy Policy and Innovation, *Energy Primer: A Handbook for Energy Market* Basics 72 https://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf ("[C]apacity markets are intended to provide more certainty for investment in new capacity resources while including an opportunity for all resources to recover their fixed costs over time.").

[34] The terms of the Order, moreover, could have substantive impact on Tri-State's ability to make energy sales at market-based rates through authority granted to it by FERC. *See, e.g.*, *Tri-State Generation and Transmission Ass'n,* 170 FERC ¶ 61,220, at PP 1, 22 and ordering para. (A) (2020) (generally providing Tri-State with authorization to transact at market-based rates). The circumstances are analogous for Platte River. Platte River also makes energy sales at market rates, but, as a government utility exempt under FPA Section 201(f), Platte River does not need market-based rate authority from FERC.

Petitioners the right to seek recovery.[35] And conflating recovery from SPP with constitutional just compensation is particularly inappropriate here because recovery from SPP, of which Petitioners are a part, means that "cost recovery" would in significant part come from the pockets of ***Petitioners themselves***.[36] The Takings Clause does not permit the federal government to appropriate control and use of property while leaving the owner without a mechanism to obtain just compensation from the government itself.

Petitioners raised these problems in their initial request for rehearing, and in their subsequent request for rearing to the DOE's second order, but the most recent Order fails to resolve them. It remains the case that the altered geographic framing of the asserted emergency over the course of the DOE's orders creates uncertainty as to how Petitioners can seek recovery. Despite this continued uncertainty, if Petitioners must continue to dispatch Craig Unit 1 for the entire emergency period

[35] Petitioners therefore request clarification of which "ratepayers" DOE is referring to in the Order, such as SPP ratepayers, all ratepayers within the WECC–Rocky Mountain region, or ratepayers for all co-owners of Craig Unit 1.

[36] For example, Tri-State comprises approximately 52% of the SPP West load but owns only 24% of Craig Unit 1. Additionally, there are co-owners of Craig Unit 1 that are not participants in SPP, who will bear costs without any apparent mechanism of recovery through SPP. If costs are allocated in proportion to load, and recovery in proportion to ownership, Tri-State and other co-owners who do not participate in SPP stand to lose. Routing recovery through SPP may obligate these co-owners to fund more than half of the costs imposed by the Order, effectively compelling them to subsidize purported reliability benefits for others. *See* Tri-State 2026 Resource Adequacy Annual Report (2026), https://tristate.coop/sites/default/files/PDF/resourceplan/Resource%20Adequacy_2026.pdf (showing excess resources in Tri-State's footprint through 2035); Platte River Power Authority Resource Adequacy Report 2025 (2025), https://prpa.org/wp-content/uploads/2025/04/PRPA_RA2025_-signed.pdf (showing excess resources in Platte River's footprint through 2030).

until 2034, costs could exceed millions in operating and maintenance costs, exclusive of fuel costs.

Moreover, even if Petitioners can and do recover some costs through this process, it is still not *just compensation* within the meaning of the Takings Clause. "[O]nce the government executes a taking, the Constitution does not permit it to shift the public's burden of just compensation to third parties. When property is taken for public use under the Fifth Amendment, the public—and not specific individuals or groups at the order of the government—must pay." *Carson Harbor Village, Ltd. v. City of Carson*, 353 F.3d 824, 831 (9th Cir. 2004) (O'Scannlain, J., concurring); *see also U.S. Bank, Nat'l Assoc. v. SFR Invests. Pool 1, LLC*, Case No. 15-cv-00287-APG-GWF, 2016 WL 1248704, at *5 (D. Nev. Mar. 28, 2016) ("[A] takings claim requires just compensation from the government, not from a private third party."); *Baker v. City of McKinney*, 608 F. Supp. 3d 457, 465–67 (E.D. Tex. 2022) (plaintiff was entitled to full compensation for a taking by police even though she obtained additional money from donations).

Accordingly, first and foremost, Petitioners' right to just compensation cannot be satisfied by reference to Section 202(c)'s cost recovery authorization.

Second, the inadequacy of this provision is particularity acute where, as here, at least some of Petitioners' relief will come from Tri-State's members and Platte River's ratepayers, even if FERC orders some level of cost recovery.[37] DOE cannot

[37] As noted in the Order, a significant driver of the growth in the demand for energy nationwide is data center demand. *See* Order at 5. To the extent the alleged emergency has been caused by the demands of data centers, shifting the costs of Craig Unit 1 onto Petitioners

simply transfer the constitutional obligation to provide just compensation onto private parties—including, here, rural communities and the residents of four small Colorado municipalities—through regulatory mandates without satisfying its own Takings Clause obligations.

II. THE ORDER DISRUPTS PETITIONERS' RELIABILITY PLAN AND FAILS TO ACCOUNT FOR VIABLE ALTERNATIVES

Separate from whether DOE must compensate Petitioners for the impact of the Order on their property and operations, the Order suffers from statutory and constitutional defects.

First, the Order fails to identify an emergency that meets the requirements of Section 202(c), or that is addressable by keeping Craig Unit 1 open. The issues articulated by the Order are fundamentally mismatched—temporally and geographically—with the Order's methods. Forcing Craig Unit 1 to remain open is counterproductive, disrupting a considered resource planning effort aimed at addressing the very concerns DOE raises in the Order. This analytical failure renders the Order arbitrary and capricious.

Second, the rote invocation of an "emergency" does not waive Petitioners' constitutional due process rights to pre-deprivation notice and a hearing. The materials relied upon in the Order demonstrate that the alleged resource-adequacy concerns are not sudden or unforeseen but instead involve long-term conditions

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and their ratepayers is contrary to President Trump's pledge to protect ratepayers from these effects. *See* Ratepayer Protection Pledge, Proclamation No. 11014, 91 F.R. 11439 (Mar. 4, 2026).

projected to arise years in the future. And where, as here, DOE had ample time to deliberate, the asserted need to address an emergency eight years in the future does not excuse DOE's failure to provide notice and an opportunity for Petitioners to be heard before imposing the Order.

Third, the Order does not meet the requirements of Section 202(c). It does not limit the Order to a remedy necessary to address the emergency, and it does not consider reasonable alternatives as required by Section 202(c) (including Petitioners' carefully calibrated reliability planning, using both thermal and renewable resources based on findings supported by objective, industry-leading forecasting methods). And *fourth*, the Order is inconsistent with the FPA's objectives. The Order is, therefore, contrary to law and arbitrary and capricious.[38]

A. The Order Describes Speculative Energy Shortfalls in 2034, and Therefore Does Not Establish the Existence of an Emergency Addressed by Requiring Continued Operation and Dispatch of Craig Unit 1

Section 202(c)(1) provides that DOE may issue an order when it determines "an emergency exists," and that the emergency was caused by "a sudden increase in

[38] As DOE is aware, Petitioners have already taken and will continue to take steps to comply with the Order. This includes incurring compensable costs and expenses. Although the Order is improper under Section 202(c), Petitioners are nonetheless entitled to cost recovery under Section 202(c) and as a compensable taking. Petitioners note that Section 202(c) is an emergency provision, and, for that reason, recovery pursuant to its terms should not turn on an ultimate determination of the lawfulness of the Order. Further, the Order (and prior substantially similar orders) provided notice to all potential ratepayers that rights to recovery would accrue to Petitioners (and the other co-owners) beginning on December 30, 2025. To bar Petitioners from recovering these already-incurred costs would be inconsistent with Section 202(c)'s purpose to respond to emergency conditions and would violate constitutional protections. Petitioners' position is based on currently available facts and information. Petitioners reserve all rights.

the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes[.]" 16 U.S.C. § 824a(c)(1). DOE's regulations define an emergency as an "unexpected inadequate supply of electric energy" and envision use of Section 202(c) to address a "specific inadequate power supply situation." 10 C.F.R. § 205.371 (2026). These regulations acknowledge that "inadequate planning or the failure to construct necessary facilities" may lead to an emergency—but also indicate that 202(c)'s role is to provide short-term relief. As DOE explained in its rulemaking:

> The DOE does not intend these regulations to replace prudent utility planning and system expansion. This intent has been reinforced in the final rule by expanding the "Definition of Emergency" to indicate that, while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.[39]

As DOE admits, Section 202(c) is focused on short-term problems with specific solutions. *Accord* 10 C.F.R. § 205.371 (where inadequate planning causes an emergency, DOE states that "the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed"). DOE's longstanding regulations confirm that Section 202(c) authority is not intended as a substitute for long-term planning or resource development, but as a temporary tool to address unexpected shortfalls—the opposite of the long-horizon concerns cited in the Order.[40]

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[39] Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39984 (Aug. 6, 1981).

[40] Notably, DOE has not attempted to update these definitions to conform the agency's defined causes of an "emergency" with the novel approach of its Section 202(c) orders.

A speculative "emergency" occurring eight years or more in the future is not a "specific inadequate power supply situation" as required by DOE's regulations for a Section 202(c) order, nor is it an example of a "sudden increase in the demand for electric energy."[41] Structural changes in electricity markets are precisely the kind of issue addressed by long-term collaborative planning by utilities, communities, and state governments. And while the Order alludes to potential future shortages in the WECC–Rocky Mountain region, it fails to specify where within the WECC–Rocky Mountain area a shortage is expected to arise, how Craig Unit 1's output would be deliverable to the locations of concern, or why existing reserves, imports, or market mechanisms would be inadequate to address the risk. This is particularly egregious given both the demonstrable effect on the reliability of Craig Station's facilities and broader impacts on Colorado communities caused by the consumption of finite water and fuel resources. The Order is therefore contrary to law and arbitrary and capricious.

1. Keeping Craig Unit 1 Open Does Not Address Long-Term Concerns

DOE rests the Order on concerns that, as mentioned *supra*, are predicted to occur at least thirty 90-day renewal cycles in the future, yet the Order requires Petitioners to take action now. To justify the Order, DOE relies principally on: (1) NERC's 2025 LTRA; (2) the 2025 WECC Western Assessment of Resource

[41] To the extent DOE's position is that the intended closure itself precipitated an emergency, that position holds no water where that closure was carefully planned and noticed for nearly a decade.

Adequacy; (3) expressions of concern by two Colorado Public Utilities Commissioners concerning the ability of a separate utility, PSCo, to meet summer 2026 loads; and (4) the 2026 NERC Summer Reliability Assessment. Order at 2–6. None of these justifications rationally support the Order, let alone establish that requiring Craig Unit 1 to operate now will address the asserted emergency.

The 2025 LTRA expressly provides—and DOE acknowledges—that there is no elevated risk for energy shortfalls over the next five years. As the LTRA shows, actual reserve margin and planning reserve margin are above the reference margin level through 2033, and NERC anticipates ***no*** loss-of-load hours (LOLH) through 2029 for the WECC-Rocky Mountain region. To the contrary, the materials DOE relies on show that in the WECC-Rocky Mountain subregion, the number of projected LOLHs will remain comfortably below DOE's benchmark for reliability over the next decade (so long as planned resource additions roughly approximate current expectations).[42] Indeed, even if actual resource additions fall *well* below projections, it will be more than six years until the number of LOLH hours in a year *may* exceed DOE's own standards.[43] Put plainly, the WECC-Rocky Mountain Region is expected to meet

[42] WECC's analysis indicates that if 85% of planned generation is built, there will be only four LOLH hours in the Rocky Mountain region in the next 10 years (20 LOLHs below DOE's threshold). *See 2025 Western Assessment Supplemental Information*, WECC [https://feature.wecc.org/warasupplemental/index.html] (last visited April 29, 2026); U.S. Dep't of Energy, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid 4 (July 2025), https://www.energy.gov/ sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY %207%29.pdf.

[43] Even in a scenario where only 67% of currently planned generation is built, it is not until 2032 that WECC projects a possibility of more than 2.4 LOLH hours in a single year. *See 2025 Western Assessment Supplemental Information*, WECC ([https://feature.wecc.org/warasupplemental/index.html] (last visited April 29, 2026).

DOE's reliability benchmark for years to come without Craig 1. The region is projected to add sufficient generating capacity to meet demand, and NERC does not expect any hours—now or in the next several years—when there will not be enough electricity to serve customers. The evidence DOE relies upon confirms that no resource adequacy concerns are likely to appear in the region until well into the 2030s.

Keeping Craig Unit 1 online ***now*** simply does not meet the terms of an emergency predicated on potential resource adequacy issues eight or more years in the future, particularly given that as Craig Unit 1's operations are further extended past its intended lifespan, it is likely to experience more and longer periods of outage. Moreover, given that operating Craig Unit 1 ***now*** depletes the fuel stockpile for Craig Units 2 and 3, the Order's actions today may ***create*** reliability concerns that would not exist were Craig Unit 1 to shut down as originally scheduled.[44]

NERC's 2026 Summer Reliability Assessment, which addresses near-term considerations, also provides no support for the Order. NERC's assessment is that reserves in the WECC-Rocky Mountain region are adequate to meet the sub-region's

[44] DOE also predicates its emergency in part on the WECC-Rocky Mountain subregion's alleged "challenges from an aging thermal resource fleet, which can lead to unplanned outages, exacerbated by supply chain issues, and vendor availability." Order at 3 (citation omitted). DOE's citation, however, is incorrect: the 2025 LTRA does not cite the age of the subregion's thermal fleet as an operational and planning issue. Rather, the LTRA identifies supply chain issues, unplanned discovery work, and vendor availability for repairs at both thermal and hydropower sites as a concern for the region. 2025 LTRA at 161. Moreover, forcing Craig Unit 1 to continue operating to address projected shortfalls in 2034, when it would be 54 years old, only exacerbates concerns about reliance on aging resources.

needs.[45] According to NERC, the greatest risk to reliability in Summer 2026 for WECC-Rocky Mountain comes from wildfires.[46]

2. Keeping Craig Unit 1 Open Does Not Best Address Concerns in DOE's Targeted Regions

The Order also cites reliability concerns specifically for the WECC Basin and Northwest subregions on one hand, and for the United States as a whole on the other. Order at 3–5. Even if those speculative future conditions could constitute an "emergency" under Section 202(c)—they cannot—Craig Unit 1 is located in the WECC-Rocky Mountain region, and its continued operations cannot reasonably be expected to resolve reliability concerns (also years away) in far-flung locations.[47] As noted, over a dozen of Tri-State's rate-paying Utility Members in New Mexico and Nebraska are located outside of the WECC-Rocky Mountain emergency area, but as owners of Tri-State remain obligated to pay for the costs of compliance despite no emergency being identified in the regions they serve.

B. The Order is Procedurally Inadequate on Both Constitutional and Statutory Grounds

Agencies must abide by both constitutional and statutory procedural safeguards before they act. The Fifth Amendment's Due Process Clause guarantees that no person shall be "deprived of life, liberty or property" by the federal government "without due process of law." U.S. Const. amend. V. At its core, due

[45] *See NERC 2026 Summer Reliability Assessment,* at 37 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[46] *Id.*

[47] DOE's failure to bridge this gap is especially problematic given that this Order altered the geographic framing of the asserted emergency from the DOE's initial order.

process requires notice and an opportunity to be heard before the government takes action affecting protected interests. *Memphis Light, Gas & Water Division v. Craft*, 436 U.S. 1, 19 (1978). This principle applies across regulatory regimes where hearings are generally required before agencies impose obligations or alter rights. Similarly, where a statute creates specific procedural requirements before it can take action, failure to follow these requirements renders the agency action arbitrary and capricious. *See Safari Club International v. Zinke*, 878 F.3d 316, 325 (D.C. Cir. 2017) ("A disputed action also may be set aside as arbitrary and capricious if the agency has acted 'without observance of procedure required by law.'") (citing 5 U.S.C. § 706(2)(D)).

The Order violates both constitutional due process and the procedural requirements of Section 202(c)(4)(B)'s consultation and condition-incorporation requirements. These procedural failings render the Order unlawful.

1. The Order Violates Petitioners' Constitutional Due Process Rights

Under the FPA, most Commission (*i.e.*, FERC or DOE) actions—such as rate changes or interconnection orders—cannot take effect without a prior hearing. *See generally* 16 U.S.C. §§ 824a(b), 824a(e), 824a-1(a), 824a-3(f), 824a-4, 824b(a)(4), 824c(b), 824d, 824e, 824f, 824i(b), 824j, 824j-1, 824k, 824m, 824o, and 824p. Section 202(c) orders are unusual in that they may be issued without any prior hearing, reflecting their purpose as a short-term emergency tool meant to address fast-moving and unexpected situations. *See Fuentes v. Shevin*, 407 U.S. 67, 90–91 (1972) (holding that to justify postponing notice and opportunity for a hearing before deprivation of

a property interest on basis of an "extraordinary situation," the situation must be "truly unusual.").

However, "[t]here is a relation between the kind of emergency and nature of the solution." *Pa. Gas & Water Co.*, 427 F.2d at 577. Where a hearing is feasible, its absence deprives Petitioners of due process. *See South Allegheny Pittsburgh Restaurant Enterprises, LLC v. City of Pittsburgh*, 806 Fed. Appx. 134, 139–41 (3d Cir. 2020) (holding that the manifest lack of a qualifying emergency meant that order shutting down under-21 nightclub violated plaintiff's procedural due process rights); *Chalkboard, Inc. v. Brandt*, 902 F.2d 1375 (9th Cir. 1989) (suspension of daycare employees' licenses without pre-deprivation process because of asserted categorical emergency violated procedural due process rights); *Miller v. Campbell Cnty.*, 945 F.2d 348, 353 (10th Cir. 1991) (finding emergency insufficient to avoid need for pre-deprivation hearing when two months elapsed between notice that plaintiff's homes were uninhabitable and date of planned evacuation, but concluding that sufficient pre-deprivation hearing opportunities had occurred).

The Order's emergency does not rest on an urgent and immediate need for additional generation to address a specific incident or event such as unusually extreme weather. Rather, the Order's purported emergency is based on broader concerns about the sufficiency of generation capacity and reliability in the WECC–Rocky Mountain assessment area over time and in the future. Because the Order does not demonstrate an immediate crisis, it cannot justify dispensing with the pre-deprivation hearing requirement. Petitioners, however, have received no such

process. Thus, they were deprived of their constitutional right to notice and a hearing before the Order came into effect.

Petitioners identified this Constitutional deficiency in their prior requests for rehearing. But rather than afford Petitioners due process, DOE simply issued this new Order with no additional process and with no explanation for why no process was required. Even if the initial order could be defended as emergent, the second and third orders cannot. Having received notice of the due-process defect and having had ample time to address it, DOE's decision to reissue a materially identical order without any procedural safeguard constitutes a discrete constitutional violation and is itself arbitrary and capricious.

2. DOE's Failure to Engage with the EPA Renders the Order Invalid

Section 202(c)(4)(B) mandates that DOE "consult with the primary Federal agency with expertise in the environmental interest protected by" the laws or regulations waived by a renewed order and include any conditions mandated by that agency in the order, which must be "made available to the public." 16 U.S.C. § 824a(c)(4)(B). Similarly, while DOE "may exclude such a condition from the renewed or reissued order if it determines that such condition would prevent the order from adequately addressing the emergency necessitating such order[,]" DOE must provide a public explanation of this lack of condition in the order. *Id.*

This consultation requirement is both mandatory and substantive. After all, Congress empowered DOE to take extraordinary action by extending a Section 202(c) order only *after* DOE has been made aware of the environmental impacts of renewing

an order. *Cf. Center for Biological Diversity v. Zeldin*, 171 F.4th 356, 381-83(D.C. Cir. Mar. 27, 2026) (holding that programmatic consultation did not alleviate burden of EPA to directly consult with National Marine Fisheries Service under Endangered Species Act because planned action could affect species under NMFS's jurisdiction). The FPA's direction to "consult" with relevant stakeholders obligates DOE to engage in a "meaningful exchange of information[.]" *California Wilderness Coal. v. U.S. Dep't of Energy*, 631 F.3d 1072, 1086 (9th Cir. 2011) (finding DOE failed to "consult" with the states as required by FPA Section 216).[48]

DOE does not identify ***any*** agency it consulted in promulgating the Order. At the very least, EPA, the entity that administers the Clean Air Act and other statutes most directly relevant to Craig Unit 1 and which approved Colorado's Regional Haze State Implementation Plan (of which the closure of Craig Unit 1 was a part), should have been consulted. Similarly, agencies involved with managing the Yampa River, like the Bureau of Land Management, should have been consulted concerning the obvious impact on water resources. The Order, however, does not describe any consultation with EPA, let alone any other agency. and thus contains no indication that DOE complied with an explicit statutory element of a lawfully renewed Section 202(c) order. That alone renders it unlawful. And the defect is not just procedural, but substantive. Meaningful consultation with the EPA, for instance, would inform

[48] The District Court for the District of Columbia recently held that a "late Friday afternoon, three-sentence email exchange between staffers" was insufficient to qualify as "consulting" another agency. *Miot v. Trump*, No. 25-cv-02471 (ACR), 2026 WL 266413, at *22 (D.D.C. Feb. 2, 2026), *cert. granted before judgment*, No. 25-1084, 2026 WL 731087 (U.S. Mar. 16, 2026).

DOE about the incompatibility of keeping Craig Unit 1 open with Colorado's federally-approved emissions plans and the impact of regulatory uncertainty on utilities' long-term planning around the country, as well as inform how DOE balances different options, and help identify the best alternative as required by Section 202(c).

C. The Order Failed to Limit Emergency Relief to What Is Necessary to Address the Asserted Emergency and Did Not Consider Reasonable Alternatives

Section 202(c) authorizes only those extraordinary measures that are necessary to resolve the emergency at hand, and it requires the Secretary to exercise judgment in selecting the course of action that will best meet that emergency and serve the public interest. 16 U.S.C. § 824a(c)(1)–(2). Those requirements impose meaningful limits on DOE's authority, including an obligation to confine any order to what is actually required to address the asserted emergency. The Order fails this threshold requirement. Rather than identifying a specific, imminent reliability problem that necessitates continued operation of Craig Unit 1, DOE imposes a sweeping mandate—of significant scope, duration, and operational rigidity—without explaining why that measure is necessary to address the conditions it cites. By failing to limit emergency relief to what is demonstrably required, the Order exceeds the narrow authority Section 202(c) confers and is arbitrary and capricious.

Lack of necessity is confirmed by DOE's failure to consider reasonable alternatives. Section 202(c) requires the Secretary to exercise "judgment" and select only those measures that "will *best* meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1) (emphasis added). Implicit in this mandate is the recognition that alternatives be considered and ruled out. Having been on notice—

both in Petitioners' prior rehearing requests and in the intervening months—that alternatives existed, DOE's failure to evaluate them in reissuing the Order independently renders the decision arbitrary and capricious.

DOE should have conducted and disclosed an analysis showing why the path selected is the "best" course forward, particularly in light of the potential 2034 time-horizon of the asserted emergency. *See Michigan v. EPA*, 576 U.S. 743, 753 (2015) (holding that "reasonable regulation ordinarily requires paying attention to the advantages and the disadvantages of agency decisions"). This is consistent with the emergency nature of the powers contained in Section 202(c), which should not be exercised where "alternatives offered a more confined solution" to the emergency at issue.[49] *Pa. Gas & Water Co.*, 427 F.2d at 577 (considering analogous powers under the Natural Gas Act); *see also Farmers Union Cent. Exchange, Inc. v. FERC*, 734 F.2d 1486, 1511 (D.C. Cir. 1984) ("It is well established that an agency has a duty to consider reasonable alternatives to its chosen policy, and to give a reasoned explanation for its rejection of such alternatives.") (citation and footnote omitted).

As with DOE's first and second orders, the Order reflects no consideration of alternatives, let alone justification for mandating that Craig Unit 1 remain active over other options, and is thus contrary to law and arbitrary and capricious. This

[49] DOE regulations for utilities applying for a Section 202(c) order to override environmental regulations require the utility to provide extensive information related to operations and alternative courses of action. *See* 10 C.F.R. § 205.373(g)–(i) (mandating that applicants provide information concerning "conservation or load reduction actions," "efforts . . . to obtain additional power through voluntary means," and "[a] listing of proposed sources and amounts of power necessary from each source to alleviate the emergency and a listing of any other 'entities' that may be directly affected by the requested order.").

failure is especially indefensible here because Petitioners specifically identified alternative approaches in their prior requests for rehearing.[50] And an "emergency" occurring eight or more years from now can be solved by any number of means: more generation, more efficient use of existing generation, load flexibility, etc. DOE nevertheless re-reissued a materially identical order six months after the initial order without assessing those alternatives or explaining why they were inadequate. Whatever urgency DOE might initially claim, it cannot excuse reissuing a materially identical order without engaging with the alternative approaches identified by Petitioners and explaining why mandating that Craig Unit 1 remain active is the "best" measure to address this long-term reliability concern across the region described in the Order.[51]

Moreover, the long-term nature of the "emergency" articulated by DOE reinforces the need to consider alternatives and broadens the scope of what must be considered. While the "menu" of emergency responses to a sudden and unexpected

[50] Request for Clarification and Rehearing of Order No. 202-25-14 at 31; Request for Clarification and Reheaing of Order No. 202-26-21 at 37 Petitioners identified the possible alternatives of: (1) DOE and/or FERC "proceeding through the rulemaking process pursuant to section 403 of the Department of Energy Organization Act, 42 U.S.C. § 7173, to devise a plan to ensure reliability through a more fulsome, consultative process[;]" and (2) DOE "evaluat[ing] whether it had authority to take proactive action to insure that 'new resources' in the region are not 'significantly delayed.'"

[51] That Craig Unit 1 has been dispatched since Order No. 202-25-14 was issued does not demonstrate that keeping it in operation and available for dispatch either responds to DOE's asserted "emergency" in any way, or that it is the *best* such response when alternatives are considered (none were). SPP's decision to call on the tools in its toolbox is unrelated to whether DOE's decision to mandate that Petitioners place the tool in its toolbox is reasonable or justified by its Order.

crisis caused by natural disaster may be limited, the menu of policy options to address reliability concerns eight years in the future is not.

Similarly, DOE's need to consider alternatives is particularly important given Craig Unit 1's status. Craig Unit 1 is an older, uneconomic unit. Due to its long-planned retirement, Craig Unit 1 has experienced years of prudently deferred maintenance and therefore faces particularly high costs to restore and maintain operations compared to possible alternatives. Craig Unit 1 is also consuming finite water and fuel resources needed for other units. The Order further fails to consider how mandating Craig Unit 1's continued operation interferes with Petitioners' ability to invest in or use other, more economic generation capacity and therefore undermines the very ends that it purports to advance. As previously discussed, the Axial Basin generating facility relies on the same transmission infrastructure as the Craig units. That infrastructure is already congested; when all three Craig units are operating, Craig Unit 1's continued operation could interfere with the ability of new alternatives like Axial Basin to provide economic power to the grid.

In the absence of such consideration, and disclosure of a valid rationale, Petitioners and the public "cannot weigh the merits of an agency decision nor compare it to other alternative actions[.]" *Rocky Mountain Wild v. Bernhardt*, 506 F. Supp. 3d 1169, 1187 (D. Utah 2020). The Order does not discuss why Craig Unit 1's continued operation was selected as the "best" solution to the described conditions, or if alternatives were considered, what those alternatives were, and why any considered

alternatives were discarded. Thus, it is contrary to law and an arbitrary and capricious exercise of agency authority.

D. The Order Improperly Usurps the Role of State and Local Governments, Utilities, and Markets in Resource Adequacy Planning

Keeping an aging coal plant online, 90 days at a time, cannot resolve resource shortfalls eight years from now. But developing and implementing a plan to build more generation, and executing on that plan, can. This is what Petitioners—along with other utilities and state and local regulators—aim to do, and are doing. Yet, the Order interferes with these efforts: DOE's approach disrupts a complex legislated and regulated system that includes utility-led resource planning and various layers of supervision and market mechanisms. The Order disrupts these processes and makes determining and proceeding with the most efficient and effective solutions for resolving anticipated resource needs more difficult.

The FPA imposes an express jurisdictional limit on the exercise of Section 202(c). FPA Section 201(b)(1), 16 U.S.C.A. § 824(b)(1), states that FERC—and, here, DOE exercising FERC's authority—has no jurisdiction "over facilities used for the generation of electric energy" unless such jurisdiction is specifically provided for. The "States' reserved authority[,]" *Hughes v. Talen Energy Marketing, LLC*, 578 U.S. 150 (2016), includes the "[n]eed for new power facilities, their economic feasibility, and rates and services," all of which "are areas that have been characteristically governed

by the States." *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983). [52]

Under this framework, the decision of whether Craig Unit 1 should remain operational belongs to Craig Unit 1's owners, subject to oversight by state governmental units. This framework reflects, among other things, the unique privileges and obligations of public utilities. *See Jackson v. Metro. Edison Co.*, 419 U.S. 345, 357 (1974) ("The nature of governmental regulation of private utilities is such that a utility may frequently be required by the state regulatory scheme to obtain approval for practices a business regulated in less detail would be free to institute without any approval from a regulatory body.").

Utilities maintain the lead role in planning and constructing systems that ensure resource adequacy: both Tri-State and Platte River engage in reliability planning that balances system operational needs, cost and regulatory requirements. [53]

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[52] "Recognizing the careful balance that the FPA strikes between federal and state regulation" FERC recently found that "states retain exclusive authority over . . . the generation mix." *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61217, at P165 (2025). Long-term economic and planning decisions regarding Tri-State's resource mix had been approved by the State of Colorado through the 2020 and 2023 Energy Resource Plans. This jurisdictional division of responsibility and federal respect for state policymaking is also a policy of the FPA. *See Sierra Club v. FERC*, 145 F.4th 74, 81 (D.C. Cir. 2024) (respecting the role of state regulators); *NextEra Energy Res., LLC v. FERC*, 118 F.4th 361, 365 (D.C. Cir. 2024) ("[FERC] may regulate the transmission, but not the generation, of electricity[.]").

[53] Colorado's state government also plans around addressing shorter-term concerns. *See* , *e.g.*, Colo. Energy Office, Colorado Energy Assurance Emergency Plan (https://energyoffice.colorado.gov/climate-energy/colorado-energy-assurance-emergency-plan (last visited Apr. 29, 2026). The Colorado Energy Office (CEO) shares responsibility for energy assurance in the state with the Colorado PUC and state Division of Homeland Security and Emergency Management, with the PUC "primarily responsible for electric and natural gas energy emergencies." *Id.* To the extent the "emergency" is premised on shorter-term concerns, it arbitrarily fails to recognize the efforts made by utilities and state and local government to address them,

In Colorado, the Colorado Public Utilities Commission (PUC) oversees resource adequacy planning for utilities under its jurisdiction, among other regulation and coordination of the electrical-generation sector.[54] Finally, other entities play a critical role in both coordination and oversight. SPP, for instance, requires load-serving entities to maintain a certain level of Planning Reserve Margin capacity or face financial penalties, which discourages utilities from free-riding on other participants' efforts to maintain adequate generation capacity.[55]

For nearly a decade, Petitioners along with other co-owners have planned to retire Craig Unit 1 in line with resource adequacy planning. The Order attempts to supplant this process by substituting DOE's judgment for the utilities' and Colorado's long-term resource planning decisions—all to address an "emergency" so diffuse that its existence (or nonexistence) years from now is impossible to anticipate or cure. DOE's regulations recognize the distinction between the need to conduct planning and the existence of an emergency that results from inadequate planning. *See* 10 C.F.R. § 205.371 (an emergency may result "inadequate planning or the failure to construct necessary facilities" but such an emergency can be resolved through "firm

[54] *See generally* Colo. Dep't of Regulatory Agencies, PUC, Electric Resource Plans / Clean Energy Plan https://puc.colorado.gov/puc-home/energy-and-water/electric-resource-plans/clean-energy-plan (last visited April 29, 2026). The Colorado Energy Office also tracks resource adequacy in the state of Colorado. *See* C.R.S. 40-43-101 (requiring resource adequacy reports from Colorado utilities). The other states in which Tri-State operates also exercise varying degrees of oversight concerning Tri-State resources.

[55] SPP Open Access Transmission Tariff, Att. AA, § 14, https://www.spp.org/spp-documents-filings/?id=18162. SPP will begin imposing financial penalties in 2027.

arrangements"). The failure to distinguish between the two renders the Order contrary to law and arbitrary and capricious.

E. The Order is Inconsistent with the FPA's Statutory Objectives

Courts reject agency action as arbitrary and capricious if it is "inconsistent with the statutory mandate" or "frustrate[s] the policy that Congress sought to implement." *FEC v. Democratic Senatorial Campaign Comm.*, 454 U.S. 27, 32 (1981). The FPA was passed to advance various policy goals, including protecting consumers from "excessive rates and charges," *Xcel Energy Servs. Inc. v. FERC*, 815 F.3d 947, 952 (D.C. Cir. 2016) (citation omitted)); "maintaining competition to the maximum extent possible[,]" *Otter Tail Power Co. v. United States*, 410 U.S. 366, 374 (1973); and encouraging the "orderly development of plentiful supplies of electricity . . . at reasonable prices." *NAACP v. FPC*, 425 U.S. 662, 670 (1976).

By compelling an uneconomic, aging unit to remain operational well beyond its planned retirement, the Order upends the Petitioners' ability to plan their systems and act with confidence in a competitive marketplace. Because the Order is at odds with the statutory objectives of the FPA, it is contrary to law and arbitrary and capricious.[56]

CONCLUSION

Petitioners are committed to providing reliable and affordable electricity to communities across Colorado and the Mountain West, and have planned accordingly

[56] As discussed *supra*, the Order similarly contradicts President Trump's pledge to protect ratepayers from the effects of DOE's Section 202(c) orders. *See* Proclamation No. 11014.

by developing a resilient portfolio of generation resources. Petitioners seek to work constructively with DOE and other agencies to advance shared reliability and affordability goals. Actions that unsettle long-standing, state-approved planning processes, however, risk undermining those objectives, interfering with the operations of the entire Craig Station through overconsumption of water and fuel resources, and imposing unnecessary costs on the very consumers the processes are designed to protect,.

For these reasons, the Order cannot stand. It effects an uncompensated taking of Petitioners' property, denies them due process, and fails to meet Section 202(c)'s statutory requirements, including that DOE articulate a valid emergency and that DOE's chosen mandate "best meet" the stated emergency. Moreover, the Order does not address the points raised in Petitioners' first and second rehearing requests. Petitioners urge DOE to reconsider the Order.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties below. Dated at Washington, D.C., this 24th day of July 2026.

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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	)	Order No. 202-26-49

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit ZZZ: CoPUC, Tri-State, Phase II Status Update, filed on June 30, 2026, in Proceeding No. 23A-0585E

Submitted to Colorado PUC E-Filings System

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

IN THE MATTER OF THE APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN	)	**PROCEEDING NO. 23A-0585E**

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.'S PHASE II STATUS UPDATE

Tri-State Generation and Transmission Association, Inc. ("Tri-State"), through its undersigned legal counsel, respectfully submits this status update pertaining to its 2023 Electric Resource Plan ("ERP"). In particular, Tri-State is providing updates on:

1. Acquisition of resources in connection with the Commission's Phase II Decision;
2. The status of the federal funding Tri-State requested from the United States Department of Agriculture ("USDA") under the Empowering Rural America ("New ERA") Program; and
3. 2027 ERP planning.

I. BACKGROUND

On March 17, 2026, Tri-State filed a notice in this proceeding on Phase II developments related to preferred portfolio resource acquisition and federal funding.

II. UPDATE ON NEW RESOURCE ACQUISITION

1. Tri-State continues to make progress toward implementing the Phase II resource acquisitions. No additional contract executions have occurred, but Tri-State is

continuing to pursue the remaining storage bid selected in its preferred portfolio. Tri-State has continued to delay pursuit of back-up bid resources until further certainty regarding New ERA program funding is attained, as discussed below.

III. UPDATE REGARDING FEDERAL FUNDING

2. As described in previous filings, Tri-State pursued federal support for certain ERP-related activities under the USDA New ERA program to assist rural electric cooperatives in financing clean energy investments.

3. Tri-State's New ERA application was selected for an award. Tri-State executed commitment letters with the USDA for the New ERA award in late 2024 and early 2025 and began preliminary planning to utilize the funds.

4. On January 27, 2025, the incoming administration issued a directive halting the implementation of certain programs, including New ERA grants, pending further review. USDA subsequently released the funding on March 25, 2025;[1] however, as of the date of this Status Update, Tri-State has not yet obtained certainty regarding the timing of release of its award funds.

5. Tri-State will file an update on the status of New ERA funding in its ERP Annual Progress Report on December 1, 2026, within this proceeding.

IV. 2027 ERP PLANNING

6. Tri-State intends to begin stakeholder engagement in preparation for the 2027 ERP in Q4 of 2026. Tri-State intends to convene approximately four stakeholder meetings to review topics including, but not limited to, planning reserve margin study

[1] *See* USDA Press Release No. 0061-25 (March 25, 2025), available at https://www.usda.gov/about-usda/news/press-releases/2025/03/25/usda-delivers-rural-energy-commitments-provides-path-applicants-support-us-energy-independence.

and demand response potential study results, scenarios, and generic resources to be modeled in Phase I of the 2027 ERP. Tri-State will also review the requirements of Section 4.12 of the 2023 ERP Settlement Agreement with stakeholders, which addressed the 2027 ERP.

Dated this 30th day of June, 2026.

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